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RELIABILITY CORPORATION

Overview of the NERC Functional Model

August 2, 2016
Lacey Ourso, NERC Standards Developer

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Agenda

- Background information regarding the Functional Model (FM) and Functional Model Advisory Group (FMAG)
- 2016 FMAG project
- Questions

Background Information

- **Purpose of the Functional Model (FM)**:
    - Guideline that identifies the functions that must be performed to ensure that the Bulk Power System is planned and operated in a reliable manner.
    - Describes the specific tasks that are required to perform the reliability functions, and the relationships between the functional entities that perform those tasks

- **Functional Model Technical Document (FMTD):** Companion document that elaborates on various functions, tasks and relationships between functional entities.

Brief History of the FM

- **1999**: NERC Operating Committee formed the "Control Area Task Force" for the purpose of identifying tasks required for maintaining reliability.
- **February 2002**: Version 1 of the FM approved by the NERC Board of Trustees (BOT). This version focused on operation-centric tasks.
- **February 2004**: Version 2 of the FM approved by the BOT. Revisions focused on adding planning-related functions, which were not included in Version 1.
- **February 2007**: Version 3 of the FM approved by the BOT. Revisions focused on addressing alignment issues as a result of NERC Reliability Standards becoming mandatory and enforceable.
- **August 2008**: Version 4 of the FM approved by the BOT.
- **May 2010**: Version 5 of the FM approved by the BOT.

Functional Model Advisory Group

- <u>**Purpose of the Functional Model Advisory Group (FMAG)**</u>:
  1. Maintain the FM (and FMTD) to ensure the model correctly reflects the industry today, and
  2. Evaluate and incorporate new and emergent reliability-related tasks

- **FMAG reports to the Standards Committee (SC) and “advises and consults” with the Planning Committee (PC), Operating Committee (OC), and Critical Infrastructure Protection Committee (CIPC)**

Revisions to the FM and FMTD

- **FMAG to maintain FM to ensure it accurately reflects the industry today and incorporates any new or emergent reliability-related tasks. Review may be initiated by the Standards Committee, FMAG or based on any identified reliability-related need, such as:**
    - Standing/technical committees may identify an issue or area for consideration, and request the FMAG assess whether appropriate to add a new (or revise an existing) function, task or relationship
    - Industry request
- **Revision process:**
    - FMAG to work with standing committees (Operating Committee, Planning Committee, Critical Infrastructure Protection Committee) to obtain "endorsement" of technical content
    - Proposed revisions posted for industry comment period
    - SC ultimately endorses revisions to the FM and FMTD, before the documents are posted on the NERC website

FMAG Roster

Name	Organization
Jim Cyrulewski (co-chair)	JDRJC Associates, LLC
Jerry Rust (co-chair)	Northwest Power Pool
Dennis Chastain	Tennessee Valley Authority
Al Dicaprio	PJM Interconnection
Pete Heidrich	FRCC
Tony Jankowski	We Energies
Lorissa Jones	Bonneville Power Administration

Name	Organization
Ben Li	Ben Li Associates
Linn Oelker	LG&E and KU Services Company
Steven Rueckert	WECC
Tom Siegrist	Stone, Mattheis
Mike Steckelberg	Great River Energy
Mike Yealland	Independent Electricity System Operator (retired)
Joseph A. Wilson	Tacoma Power

2016 FMAG project

- **Version 5 (current version) of the FM and FMTD developed in 2009 and approved by the NERC Board of Trustees in 2010.**

- **Focus of 2016 FMAG project:**
  - Review the model to ensure it correctly reflects the industry today
  - Identify changes needed to the model as a result of new and emergent reliability-related issues
  - Identify changes needed as a result of recent NERC initiatives (*i.e.*, Risk-Based Registration initiative) and standard development projects (*i.e.*, Alignment of Terms)

Project Timeline

- **January 19-20**: FMAG meeting to identify areas for focus
- **March 8**: Inform standing committees (OC, PC, CIPC) of work underway, and obtain initial feedback (specific to area of expertise)
- **March 17-18**: FMAG meeting to develop revisions to the FM
- **April 13-15:** FMAG meeting to develop revisions to FM and FMTD
- **June 7-8:** Present proposed revisions to committee members (OC, PC, CIPC) for the purpose of obtaining feedback
- **June 15-17:** FMAG meeting to review and incorporate feedback from committees (OC, PC, and CIPC), and revise FM and FMTD

Project Timeline (cont)

- **July 20:** Obtain SC approval to post proposed revisions to FM and FMTD for informal industry comment period

- **July 22 – September 7:** Post proposed revisions for 45-day industry comment period

- **September/October**: FMAG meeting to review industry comments and revise FM and FMTD based on industry feedback

- **December:** Present final revisions to the FM and FMTD to standing committees (OC, PC, and CIPC) for endorsement

High-level Overview of Proposed Revisions

- Incorporated Glossary terms
- Consolidated ERO-related functions (Reliability Assurer function)
- Clarified planning functions (Planning Coordinator and Transmission Planner)
- Added cyber and physical security tasks (RC, BA, TOP, TO, IC, DP, GO and GOP)
- Revised tasks to clearly identify what actions are required for an Interchange transaction (IC, BA, TSP, PSE, and LSE)

Proposed Revisions to Distribution Provider

- Clarified that Distribution Provider task includes delivery to end-use customer or distribution-connected energy resource(s).
    - **Task No. 1**: Provide and operate electrical delivery ~~f~~Facilities between the ~~t~~Transmission system and the ~~E~~end-~~U~~use customer or distribution-connected energy resource.
    - **Relationship No. 3**: Coordinates with ~~E~~end-use ~~C~~customers, distributed energy resources, and Load-Serving Entities to identify new ~~f~~Facility connection needs.

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Contact information

- Jim Cyrulewski (chair)

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NARUC Links

NARUC draft Manual on DER Compensation:

- The press release announcing the notice can be found at this link: http://naruc.org/about-naruc/press-releases/pr-0721161/
- The draft Manual can be found here- http://pubs.naruc.org/pub/88954963-0F01-F4D9-FBA3-AC9346B18FB2
- The notice on the Town Hall and submitting comments can be found here: http://pubs.naruc.org/pub/89C9AF84-C105-BE86-BFF6-3B0B6526CA79

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DER – Definitions and Standards

Howard Gugel, Senior Director of Standards and Education
Distributed Energy Workshop – Panel 1
August 2, 2016

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DER – Standards Perspective

- Definition considerations
  - DER - Any non-BES real or reactive resource
  - DSM - All activities or programs undertaken by any applicable entity to achieve a reduction in Demand
- What does "synchronized" mean?
- What is "spinning reserve"?
- Voltage and frequency considerations
- Standards considerations
  - Instruct Standards development process to account for DER
  - Ensure NERC Functional Model accurately depicts DER

IEEE 1547 Standard for Interconnection of Distributed Resources with Electric Power Systems, Overview and Current Activity

NERC DER WORKSHOP

Panel 1 - Aligning the Definition of DERs

AUGUST 2, 2016

Charlie Vartanian, PE
IEEE P1547 Committee Secretary and Treasurer

Advancing Technology for Humanity

PRESENTATION OUTLINE

1) DEFINING DER IN CONTEXT OF 1547

3) ACTIVE REVISION OF IEEE 1547 RECOGNIZES THAT DER IS EVOLVING

INCLUDES EXTENDING AND ENHANCING THE STANDARD TO ADDRESS DER IMPACT TO BULK GRID PERFORMANCE, EXPANDED USES IN FRONT AND BEHIND RETAIL METER, FLEET-BEHAVIOR RISK, ETC.

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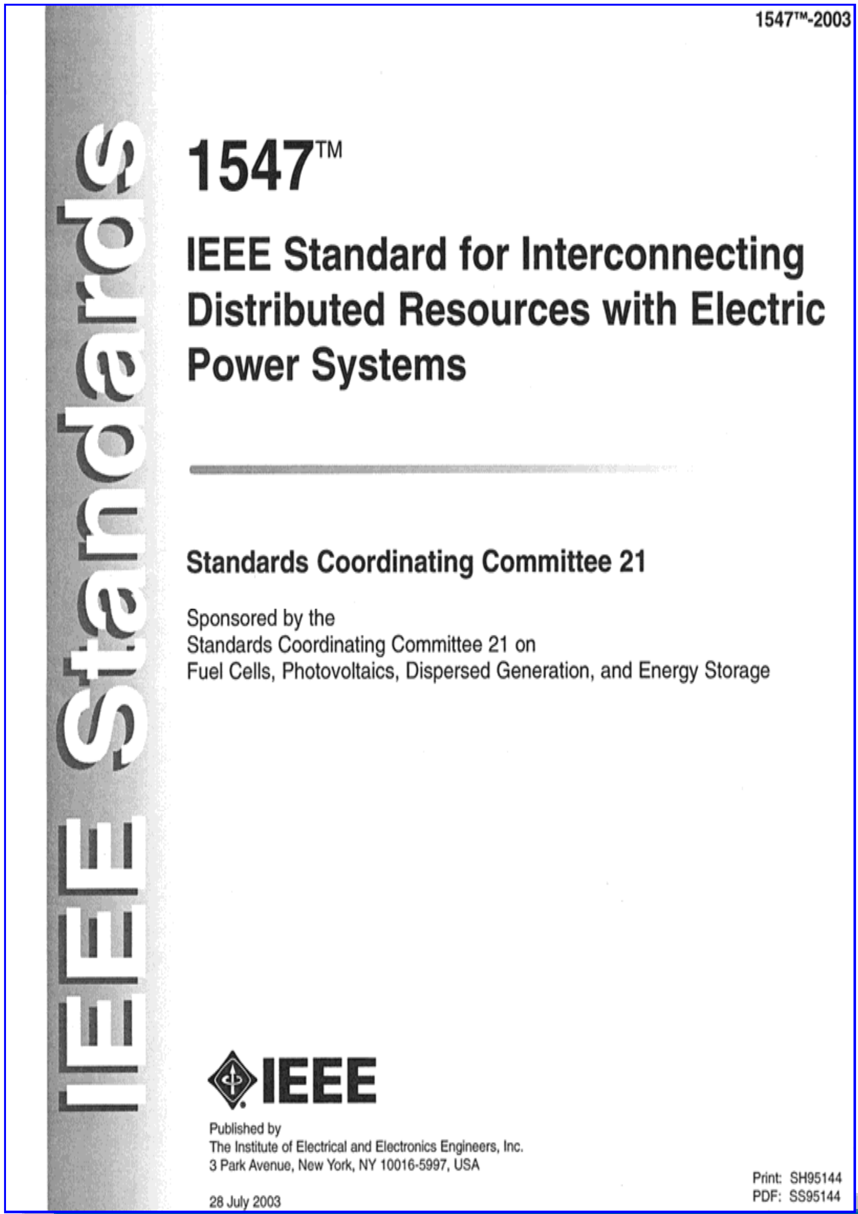
ANSI / IEEE Standard 1547

(published 2003, reaffirmed 2008; Amendment 1 2014)



1547™-2003

IEEE Standards

1547™

IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems

Standards Coordinating Committee 21

Sponsored by the
Standards Coordinating Committee 21 on
Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage

IEEE

Published by
The Institute of Electrical and Electronics Engineers, Inc.
3 Park Avenue, New York, NY 10016-5997, USA

28 July 2003

Print: SH95144
PDF: SS95144

<u>1-2-3</u> Overview, Definitions, References

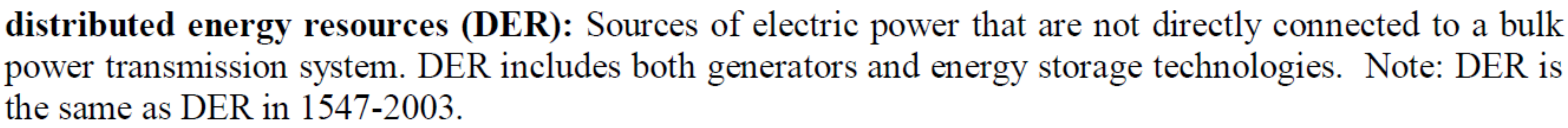
4.0 Interconnection Technical Specifications and Requirements:

- General Requirements
- Response to Area EPS Abnormal Conditions
- Power Quality
- Islanding

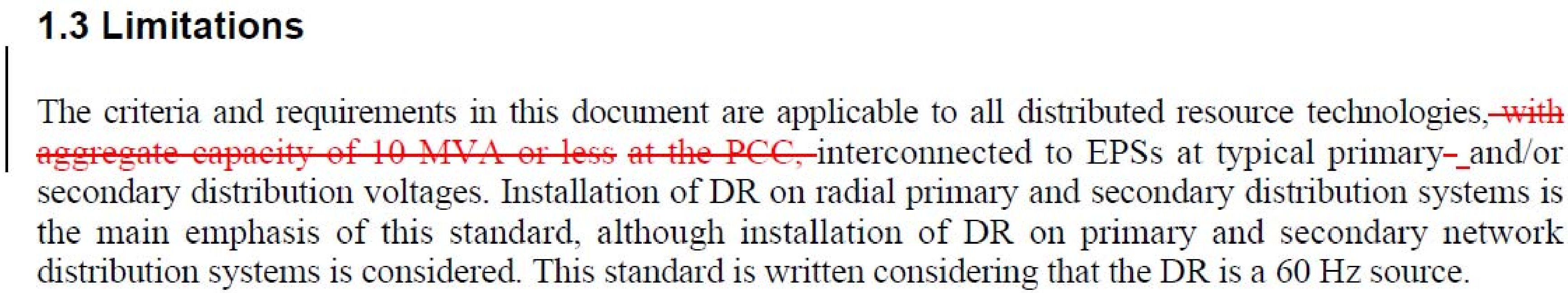
5.0 Interconnection Test Specifications and Requirements:

- DesignTests
- Production Tests
- Interconnection Installation Evaluation
- Commissioning Tests
- Periodic Interconnection Tests

DEFINING DER, P1547 REV. DRAFT



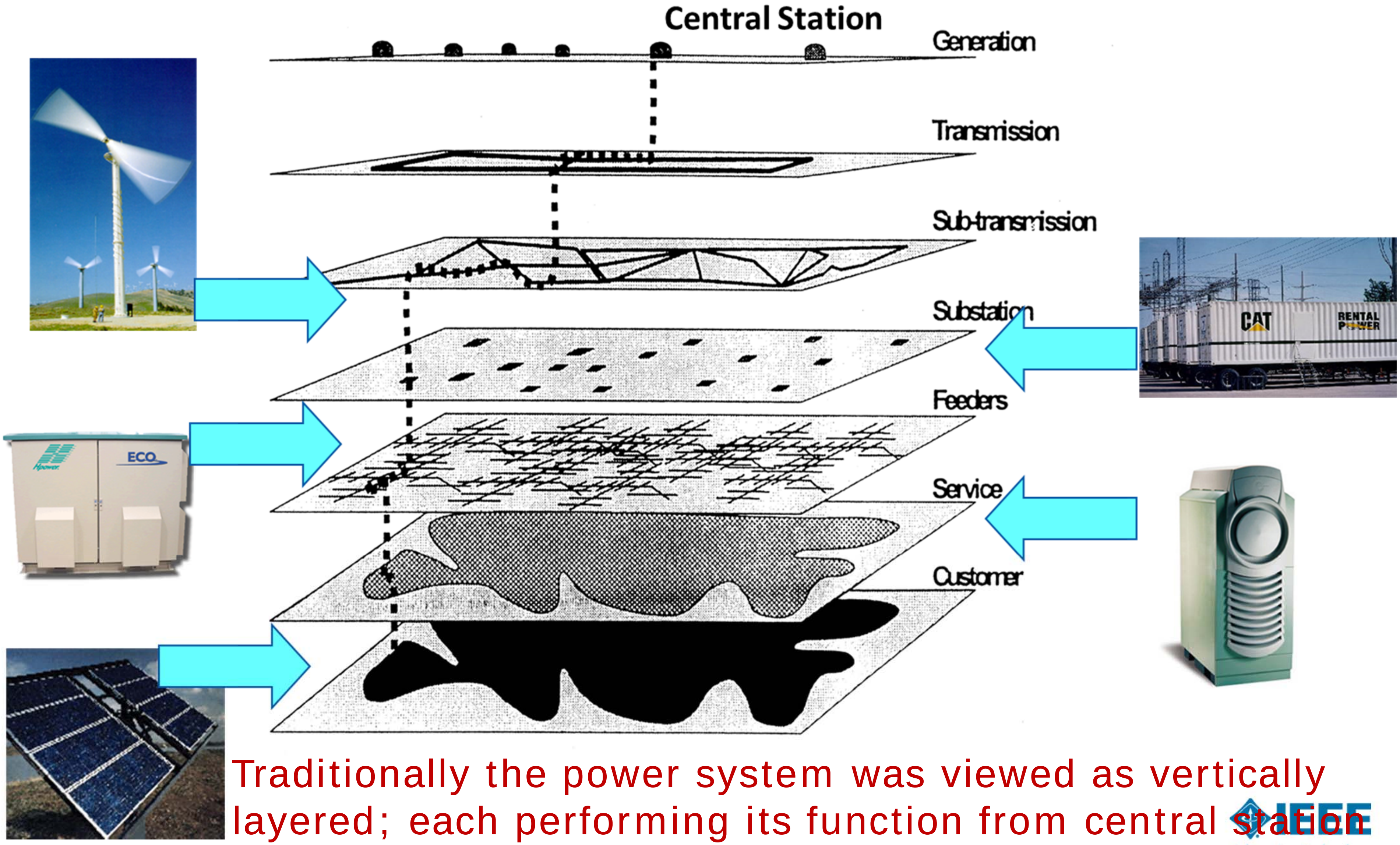
distributed energy resources (DER): Sources of electric power that are not directly connected to a bulk power transmission system. DER includes both generators and energy storage technologies. Note: DER is the same as DER in 1547-2003.



1.3 Limitations

The criteria and requirements in this document are applicable to all distributed resource technologies,~~ with aggregate capacity of 10 MVA or less at the PCC, ~~interconnected to EPSs at typical primary~~-~~ and/or secondary distribution voltages. Installation of DR on radial primary and secondary distribution systems is the main emphasis of this standard, although installation of DR on primary and secondary network distribution systems is considered. This standard is written considering that the DR is a 60 Hz source.

Interconnecting Distributed Energy Resources



Traditionally the power system was viewed as vertically layered; each performing its function from central station generation supplying power out to customers/loads.

P1547 Revision: Draft *Standard for Interconnection* ***and Interoperability*** *of Distributed* ***Energy*** *Resources with* ***Associated*** *Electric Power Systems* ***Interfaces***.

Scope: This standard establishes criteria and requirements for interconnection of distributed **energy** resources (D**E**R) with electric power systems (EPS), **and associated interfaces**.

Note: Interfaces defined in IEEE 2030: “a logical interconnection from one entity to another that supports one or more data flows implemented with one or more data links.

Purpose: This document provides a uniform standard for the interconnection **and interoperability** of distributed **energy** resources (D**E**R) with electric power systems (EPS). It provides requirements relevant to the interconnection **and interoperability** performance, operation, and testing, and, safety, maintenance **and security considerations**.

Std P1547 Full Revision: Work in Progress Topics

Updates to many 1547 requirements, and new requirements, are assigned to Subgroups comprised SME Facilitators and volunteer 1547 Working Group members. Drafting of proposed revisions is active. The P1547 Working Group is targeting completion of a Ballot-ready revised draft of 1547 by February 2017

Overall Document (Folder 1,)

Voltage regulation (Folder 2)

Voltage & Frequency Ride Through (Folder 3)

Interoperability Requirements (Folder 4)

Special Interconnection Requirements (Folder 5) e.g. Islanding, Energy Storage

Testing (F6)

Power Quality/Harmonics (F7)

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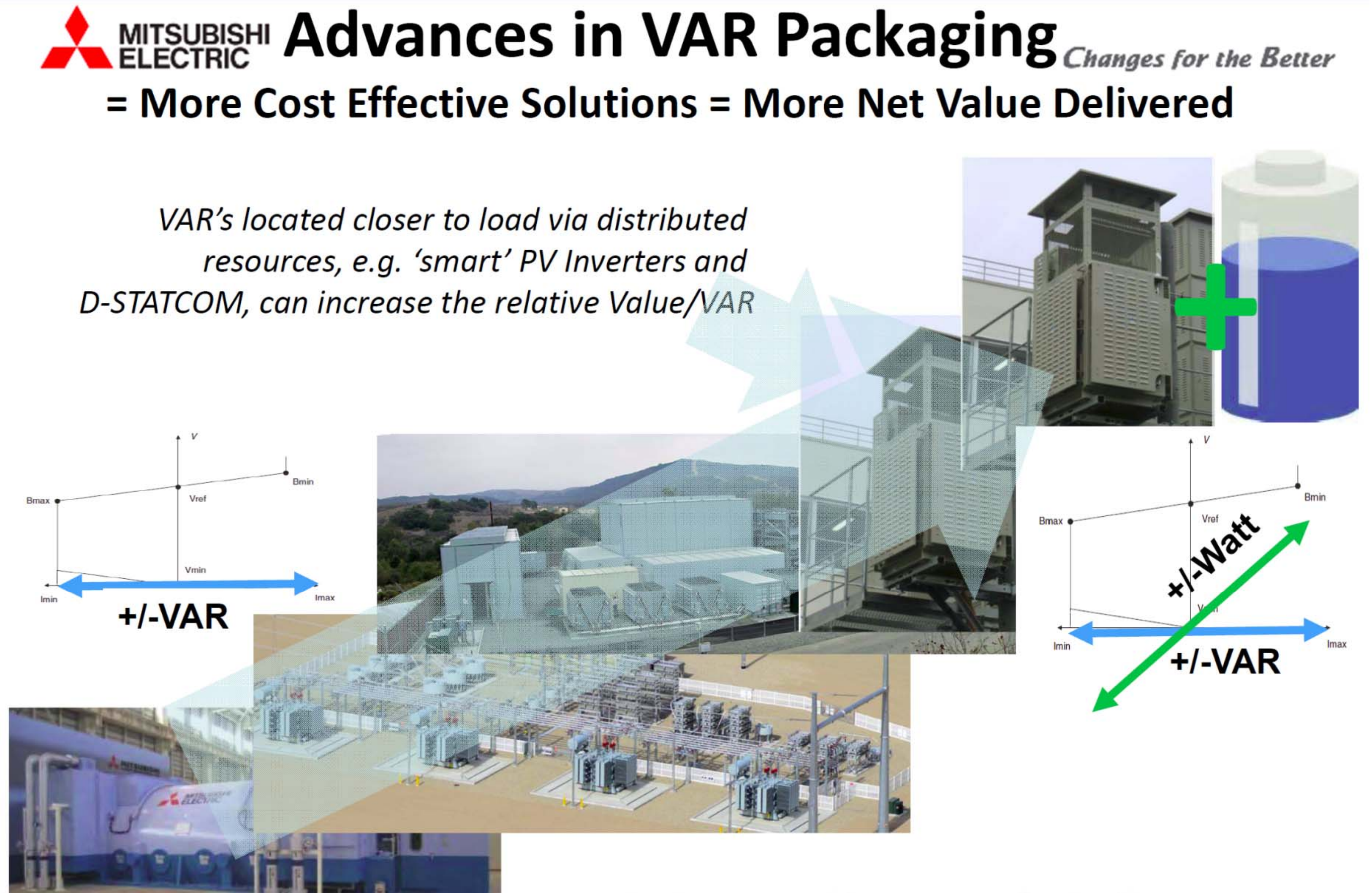
EXTENDING CAPABILITIES FROM 'T' TO 'D', ONE MANUFACTURER'S PERSPECTIVE



Advances in VAR Packaging

Changes for the Better

= More Cost Effective Solutions = More Net Value Delivered

VAR's located closer to load via distributed resources, e.g. 'smart' PV Inverters and D-STATCOM, can increase the relative Value/VAR

From "Value of VAR" panel, DoE Energy Advisory Committee Meeting, June 2015

Thank You

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626-818-5230

References and Backup Slides Follow

Opportunity to Get Involved, Next IEEE P1547 Meetings

- **October 25-28, 2016**
  - **Meeting sponsored by and location, Commonwealth Edison, Chicago Il**

- **February, 2017**
  - **Meeting sponsored by and location, NERC, Atlanta GA**

http://grouper.ieee.org/groups/scc21/1547_revision/1547revision_index.html

Ballot-ready by mid 2017

References

Using IEEE 1547

- http://www.hydroone.com/Generators/Pages/TechnicalRequirements.aspx
- http://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/canmetenergy/files/pubs/2007-172e.pdf
- https://www.sce.com/NR/sc3/tm2/pdf/Rule21_2004.pdf
- http://www.gosolarcalifornia.ca.gov/equipment/inverters.php
- http://www.energy.ca.gov/sb1/index.html
- http://www.cpuc.ca.gov/PUC/energy/rule21.htm

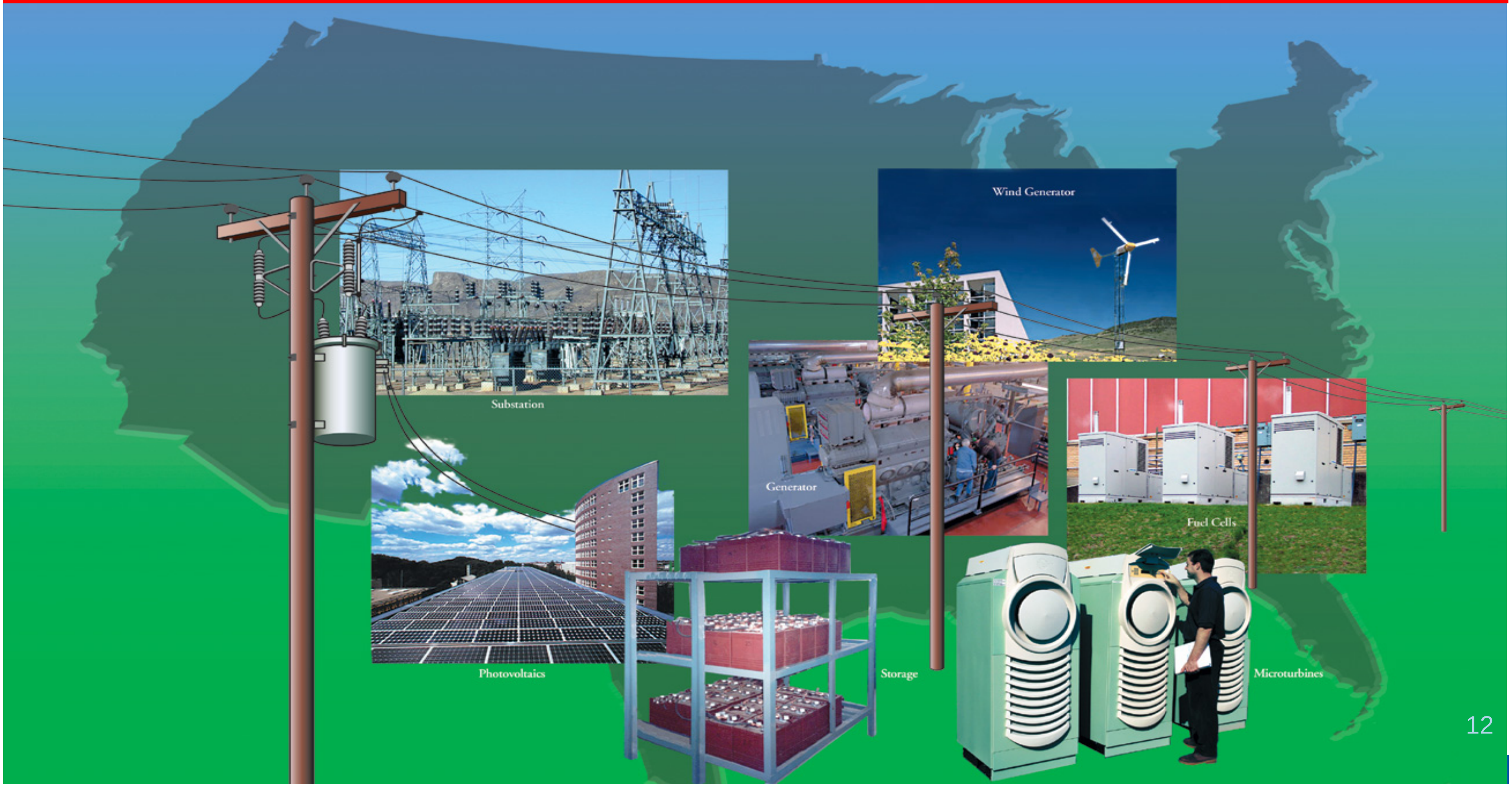
IEEE Reference Materials and Standards

- IEEE standards for sale http://www.techstreet.com/ieee/
- IEEE SCC21 Standards web site, http://grouper.ieee.org/groups/scc21/
- IEEE-SASB Bylaws: http://standards.ieee.org/develop/policies/bylaws/index.html
- IEEE-SASB Operations Manual: http://standards.ieee.org/develop/policies/opman/

Further Background Information

- Basso, T.; “Standards for DER -- IEEE 1547 (Interconnection) & IEEE 2030 (Interoperability)” NREL/5D00-63157;Nov. 2014; www.nrel.gov
- Siira, M. Interconnection, interoperability for integration in the Smart Grid;” Consulting-Specifying Engineer Magazine; March 2014, www.csemag.com
- Siira, M. “Best Practices In Electric Power System Testing For Improved Availability;” March/April 2014 PowerLine Magazine; www.EGSA.org

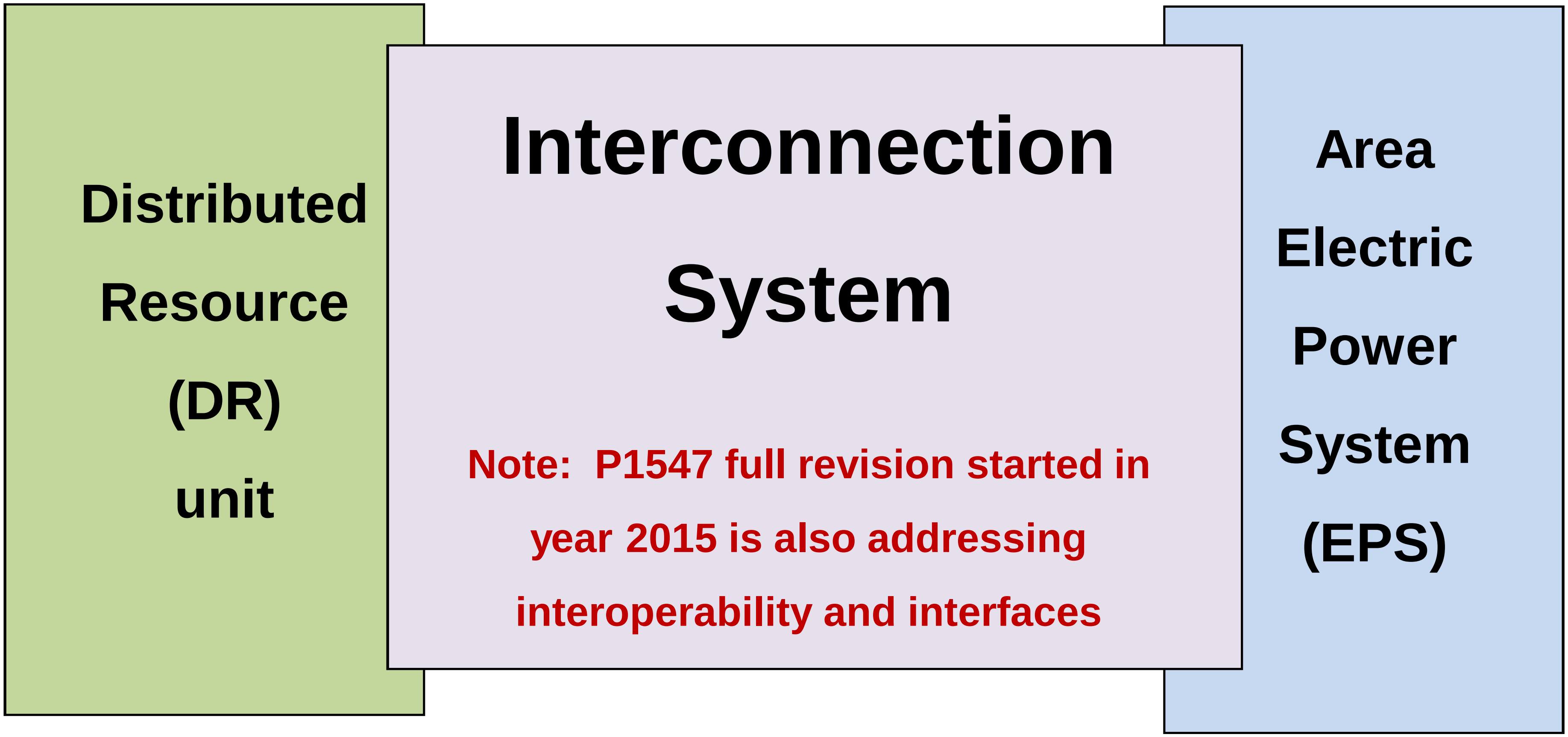
- Energy Policy Act (2005) Cites and requires consideration of IEEE 1547 Standards and Best Practices for Interconnection; all states use or cite 1547.
- Energy Independence and Security Act (2007) IEEE cited as a standards development organization partner to NIST as Lead to coordinate framework and roadmap for Smart Grid Interoperability standards and protocols {IEEE 1547 & 2030 series being expanded};
- Federal ARRA (2009) Smart Grid & High Penetration DER projects {*use IEEE stds*}.



1547: Interconnection Is The Focus

IEEE Std 1547 covers:

- **INTERCONNECTION** TECHNICAL SPECIFICATIONS & REQUIREMENTS
- **INTERCONNECTION TEST** SPECIFICATIONS & REQUIREMENTS



Distributed Resource (DR) unit

Interconnection System

Note: P1547 full revision started in year 2015 is also addressing interoperability and interfaces

Area Electric Power System (EPS)

IEEE 1547 Interconnection Standards Use in USA

IEEE 1547

Interconnection System and Test Requirements

- Voltage Regulation
- Grounding
- Disconnects
- Monitoring
- Islanding
- etc.

IEEE 1547.1

Interconnection System Testing

- O/U Voltage and Frequency
- Synchronization
- EMI
- Surge Withstand
- DC injection
- Harmonics
- Islanding
- Reconnection

UL 1741*

Interconnection Equipment

- 1547.1 Tests
- Construction
- Protection against risks of injury to persons
- Rating, Marking
- Specific DR Tests for various technologies

NEC**

Article 690 PV Systems;

Article 705: **interconnection systems (shall be suitable per intended use per UL1741)**

PJM Interconnection, Inc.

Small Generator Interconnection Standards

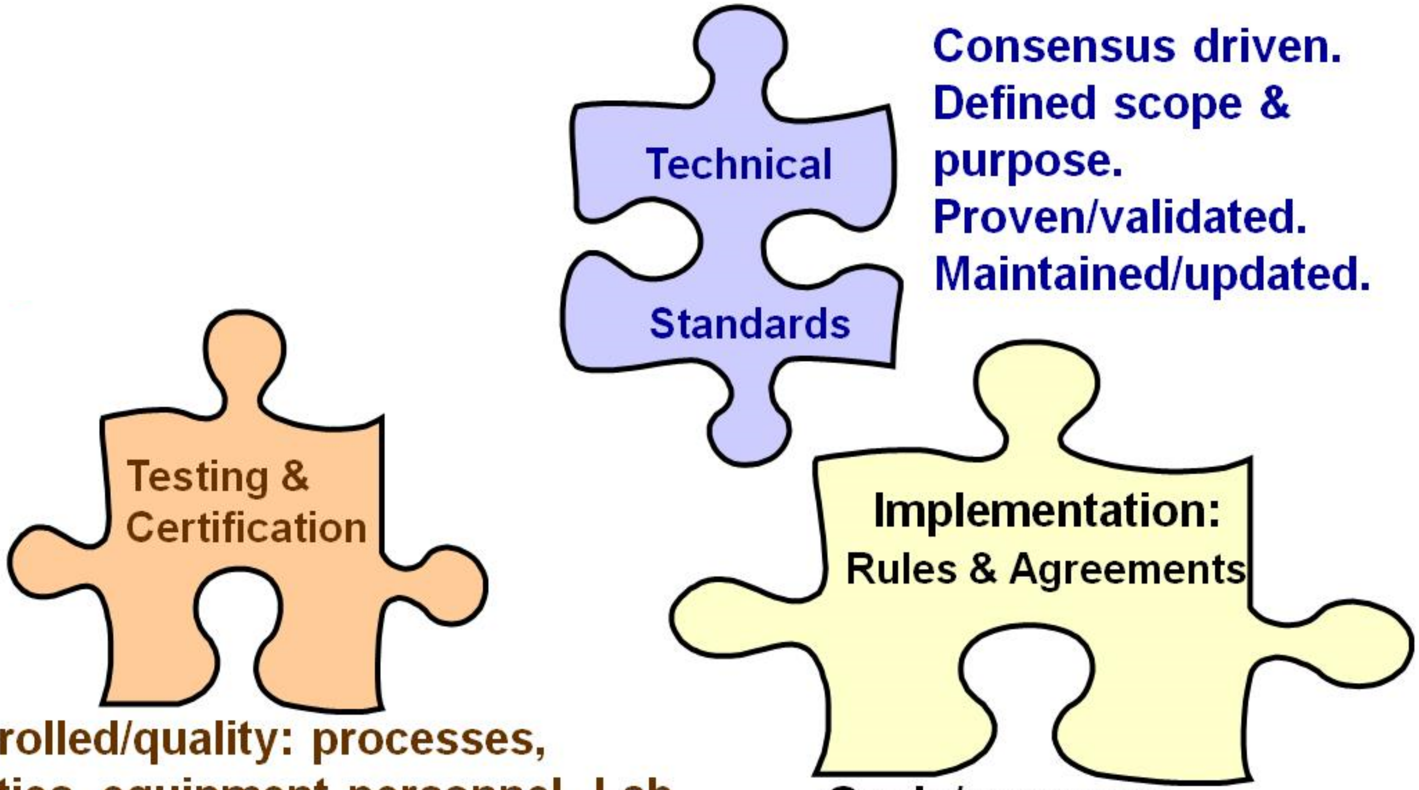
FERC approved

(0-to<10MW and 10-to-20 MW; incorporate 1547 and 1547.1)

* UL 1741 supplements and is to be used in conjunction with 1547 and 1547.1

** Articles: 480 Storage Batteries ;
692 Fuel Cell Systems;
694 Wind Electric Systems
(NEC info. based on NEC 2011)

Putting the Pieces Together:
Standards, Testing, and Implementation



Consensus driven.
Defined scope & purpose.
Proven/validated.
Maintained/updated.

Controlled/quality: processes, facilities, equipment personnel. Lab accreditation.
Manufacturer quality. Test @ cradle-to-grave.

Goals/purposes.
Which standards & programs?
Authority having jurisdiction.
Dispute resolution.

P1547 Central Desktop Folder Organization (F1 – F7)

P1547 Organization: P1547 Chair – Tom Basso; Secretary/Treasurer – Charlie Vartanian **P1547 Vice Chairs: John Berdner; Jim Daley; Babak Enayati; Mark Siira** **Note: each SG considers their specific inputs to testing, interoperability, and other cross-cutting aspects.**	**Subgroup Leaders: P1547 Vice Chairs & Sect'y. WG Subgroup Facilitators: see below**
F1 OD: Overall Document structure/contents/harmonization; new Annexes (informative as well as normative) Existing 1547 clauses 1-2-3, glossary, new Annex(es). 1.3 "Limitations"; security/reliability?	**Tom Basso, Lead;** Charlie Vartanian, Alt Lead. WG Facilitators: 1.3 Bob Cummings & David Forrest;
F2 (GR1): General Requirements 1 (GR1), -- Voltage regulation, potential new requirements 4.1.1 Voltage regulation; and possible new general requirements.	**Babak Enayati, Lead;** John Berdner, Alt. Lead. WG Facilitators: 4.1.1 Aminul Huque;
F7 (PQ): 4.3 Power quality (4.3.1, 4.3.2, and 4.3.3)	**F7 (Power Quality) Babak Enayati, Lead,** WG Facilitator: Tom McDermott MG's
F3 (GR2): General Requirements 2 (GR2), Response to abnormal grid conditions, 4.0; 4.1 (not 4.1.1 V-regulation; not distribution secondary networks); 4.2.1; 4.2.2; 4.2.3; 4.2.4; 4.2.5; 4.2.6) Includes voltage and frequency ride through	**John Berdner, Lead;** Babak Enayati, Alt. Lead. WG Facilitators: VRT & FRT Reigh Walling and Jens Boemer

P1547 Organization: P1547 Chair – T. Basso; Secretary/Treasurer – C. Vartanian	
F4 (IIAMS): Interoperability, Analysis, Modeling and Simulation? 4.1.6 Monitoring provisions (information, SCADA, etc.); Interoperability/new; modeling and simulation/new?	**Mark Siira, Lead;** Tom Basso, Alt. Lead. WG Facilitators: Frances Cleveland, Wayne Stec, Mike Ropp
F5 (SI): Special Interconnections (special EPS's and special DER-EPS considerations) 4.4 islanding; Microgrids (MG)/new; 4.1.4 Secondary distribution networks; special EPSs/new	**Charlie Vartanian, Lead**; Tom Basso, Alt. Lead; WG Facilitators: - 4.1.4 Networks Mike Coddington & Dan Musogovan; - 4.4 Islanding Leo Casey, Storage Richard Bravo; Microgrids Babak Enayati
F6 (IST): Interconnection/Interoperability Test Specifications and Requirements all of existing 5; new 5.1.7 DER short circuit response; and new 5.1.8 DER response to Loss of load; modeling and simulation/new; and, this "Testing" folder needs to be filled from all of previous topical areas.	**Tom Basso, Interim Lead;** Mark Siira, Alt. Lead. WG Facilitators: NEEDED, -5.1.7 & 5.1.8

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Modeling of DER in Bulk System Planning Studies

Jens Boemer, Eknath Vittal,
Aidan Tuohy, Daniel Brooks, Tom Key

NERC Distributed Energy Resources Workshop,
August 2-3, 2016, Atlanta, GA

August 2, 2016

Content

I. Background and Motivation

II. Bulk System Planning Studies with DER

III. Draft DER TF Report Chapter 3 on “Modeling of DER in bulk system planning studies”

IV. Implications for setup of bulk system models including DER

V. Data requirements and information sharing across the T&D interface

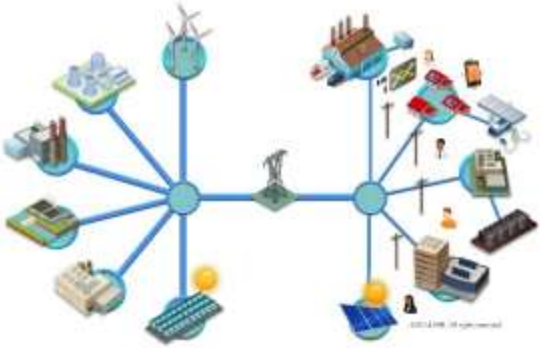
VI. Conclusions

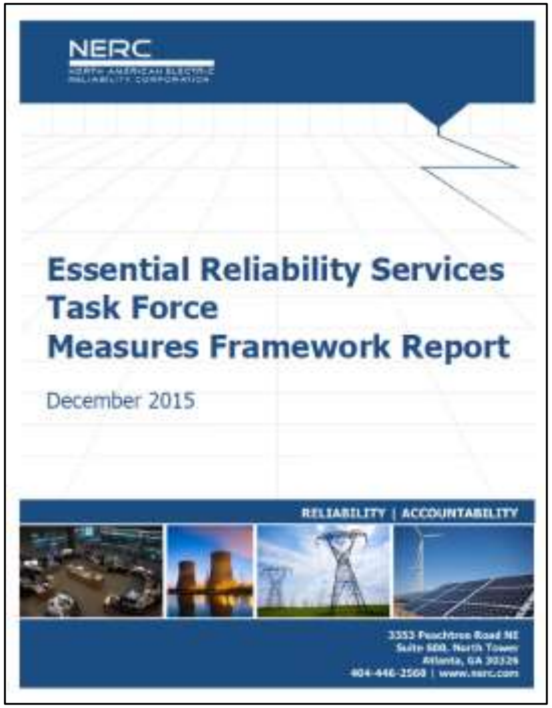
I. Background and Motivation

- EPRI’s Integrated Grid

- NERC’s DER Task Force was formed in response to Recommendation #5 in the ERSTF Framework Report (Dec. 2015).

- Among others, DER TF’s scope includes:
  - Facilitate **data collection efforts** and propose recommendations for improved data collection efforts in NERC.
  - Provide a recommendation for consistently **modeling** and assessing the reliability and/or operational impact of DERs in NERC’s Long-Term Reliability Assessment (LTRA) and other assessments.





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Essential Reliability Services
Task Force
Measures Framework Report

December 2015

RELIABILITY | ACCOUNTABILITY

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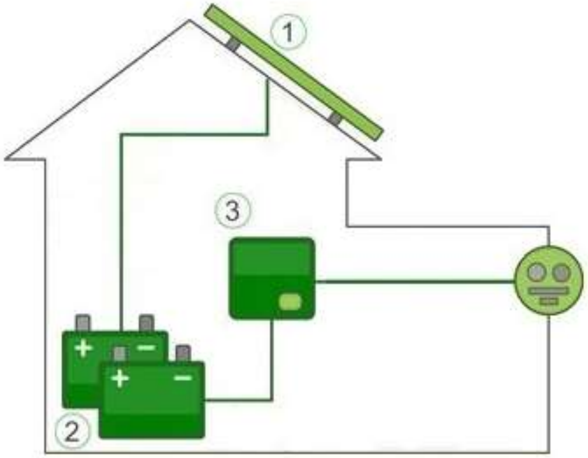
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

I. Background and Motivation

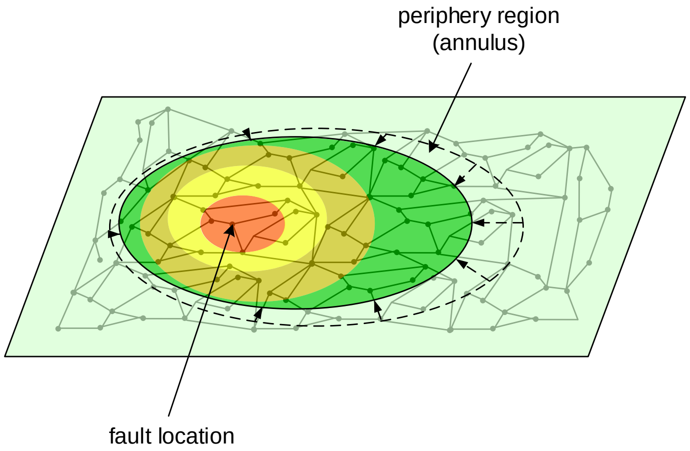


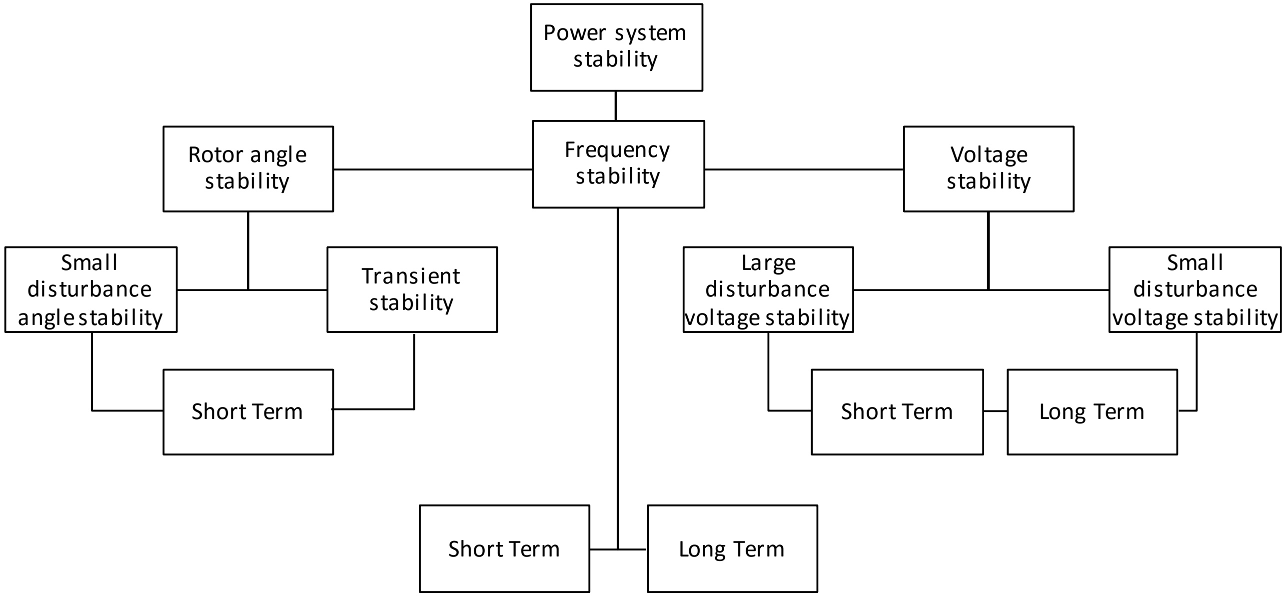
- Behind-the-meter DER is not visible to the *Transmission Planner*.
- Lack of DER data results in weak modeling assumptions and results.
- Best practices for DER data collection can be found in Germany and Spain.

Observability of behind-the-meter DER is key – both for grid operations and for grid planning.

II. Bulk System Planning Studies with DER

- Planning Study Types
  - Steady-state power flow studies
  - Steady-state short-circuit studies
  - Dynamic disturbance ride-through studies
  - Dynamic transient stability studies
  - Other (special) studies




Power system stability

Rotor angle stability

Frequency stability

Voltage stability

Small disturbance angle stability

Transient stability

Large disturbance voltage stability

Small disturbance voltage stability

Short Term

Short Term

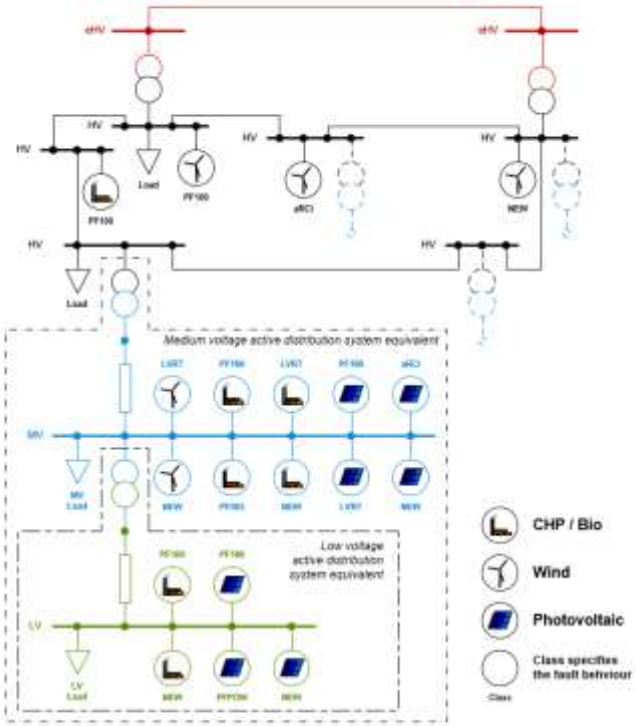
Long Term

Short Term

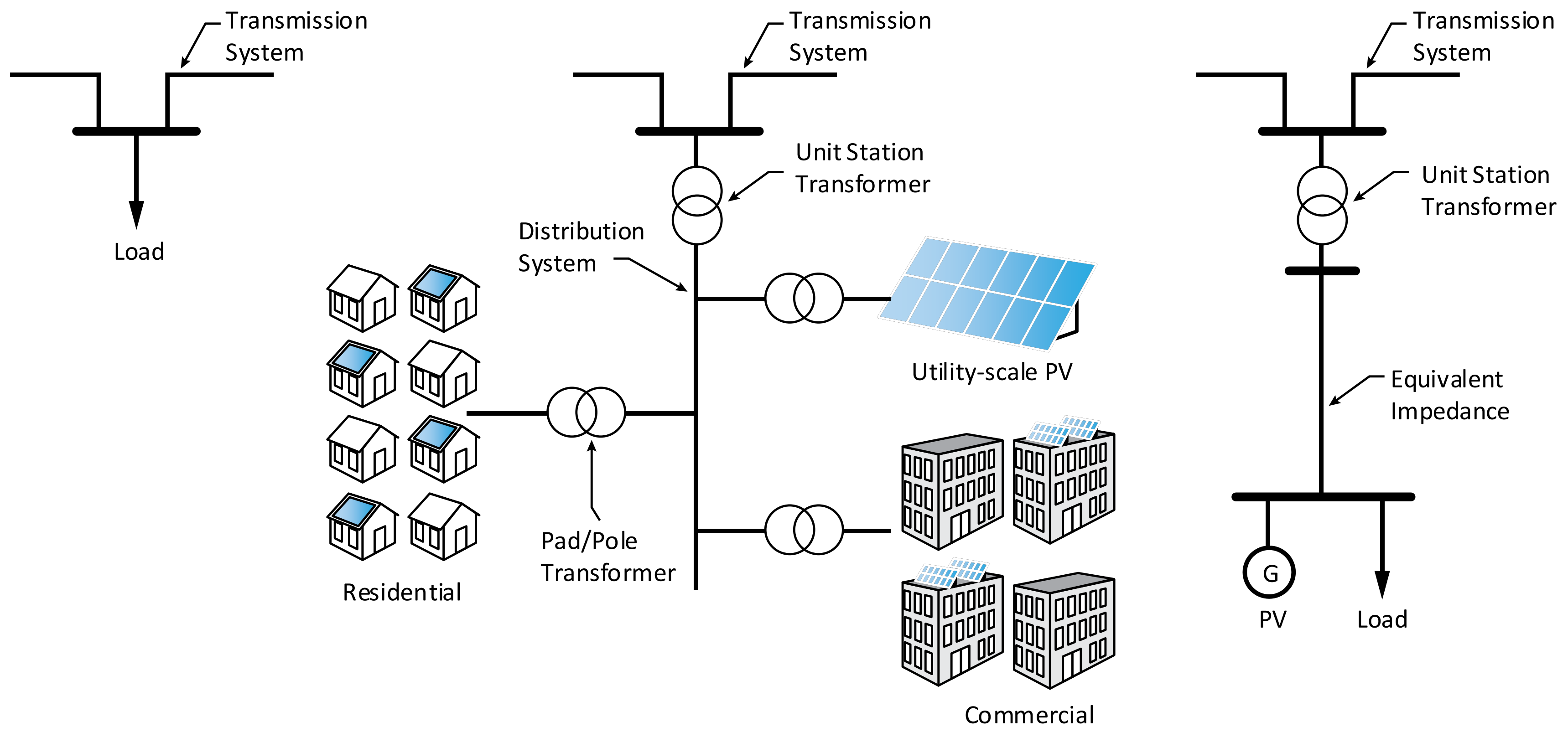
Long Term

III. Draft DER TF Report Chapter 3 on "Modeling of DER in bulk system planning studies"

- Discourage netting of DERs with load.
- Use composite load models to the extent possible and do not over-equivalize.
- Use *modular approach* to represent DERs in bulk studies:
  - Differentiation of DERs per resource type.
  - Differentiation of DERs per interconnection requirements performance.
  - Differentiation of DERs per technology-type.
- Use WECC's distributed PV (*PVD1*) model as a good starting point.



IV. Implications for setup of bulk system models including DER



Typical Load Flow Model

Transmission System

Load

High Penetration PV on Distribution System

Transmission System

Unit Station Transformer

Distribution System

Utility-scale PV

Pad/Pole Transformer

Residential

Commercial

Recommended Load Flow Model

Transmission System

Unit Station Transformer

Equivalent Impedance

G

PV

Load

Source: EPRI figure based on [1] WECC Modeling and Validation Work Group. *WECC Guide for Representation of Photovoltaic Systems In Large-Scale Load Flow Simulations.* Western Electricity Coordinating Council: January 2011.

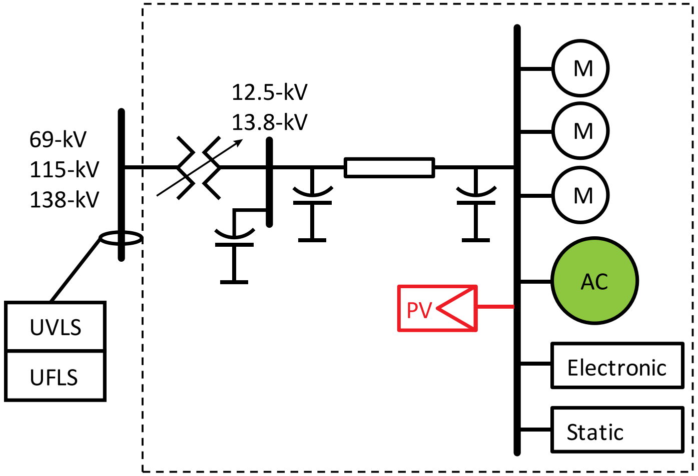
IV. Implications for setup of bulk system models including DER

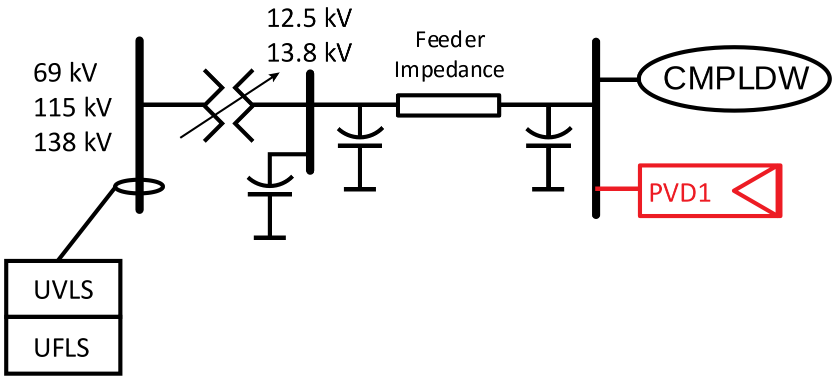
Distributed PV integrated into CMPLDW model (CMPLDWg)…?

- Single model, easy to integrate
- Many model parameters
- Limited ability to represent advanced inverter functions

Explicit representation of load and distributed PV at distribution level…?

- Multiple models, additional efforts needed to integrate
- Modular approach, incl. *PVD1*
- Flexibility to represent advanced inverter functions

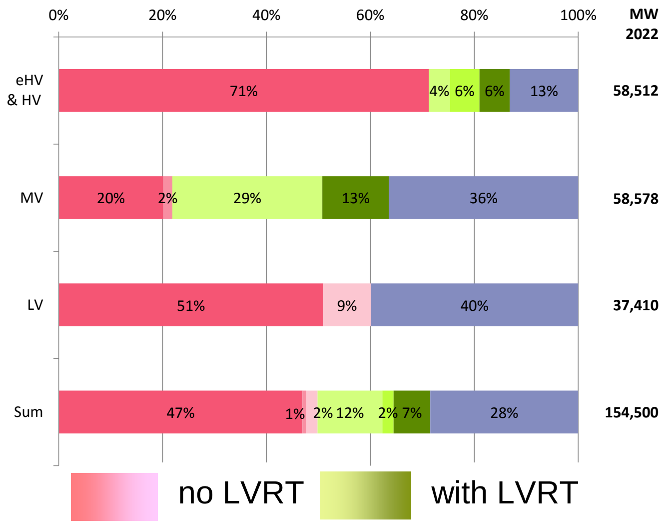




Continued EPRI research to determine reasonable balance between model accuracy and simplicity.

V. Data requirements and information sharing across the T&D interface

- DER statistics in an **aggregated** way **for each substation**, including data to represent a mix of DERs that trip and have ride-through (“legacy”).
  - DER type.
  - DER rated MVA.
  - DER rated power factor.
  - DER PCC voltage.
  - DER location: BTM / in-front-of-the-meter.
  - Date that DER went into operation.
  - DER generation profiles for planning cases.



- High-level clustering of distribution grids / a set of default equivalent impedances for various distribution grid types that can be used to choose adequate parameters for, e.g., WECC’s PVD1 model for distributed PV systems.

- Relevant interconnection performance requirements based on national or regional standards.

VI. Conclusions

- DER data collection is essential for maintaining bulk system reliability through observability and transmission planning studies.
- Modeling of DER in bulk system planning studies is an evolving study field with limited practical experience. Continued improvement of DER stability models and their parameters is recommended.
- The recommended DER data collection may be considered by the Regional Committees and specified in Regional Criteria.

Future collaborative research, knowledge exchange, and learning among industry stakeholders is needed.

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Together…Shaping the Future of Electricity

Jens C. Boemer – (206) 471-1180 – jboemer@epri.com

Utility Planning for a Sunshot Future– Innovative Practices for Incorporating Distributed Solar into Utility Planning

Lawrence Berkeley National Laboratory:

Galen Barbose (PI), **Andrew Mills***, Jo Seel, Ryan Wiser

National Renewable Energy Laboratory:

Trieu Mai, Changgui Dong, Ben Sigrin

NERC Distributed Energy Resources Workshop

August 2, 2016

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Project Overview

Context

- Part of a multi-year research agenda to inform strategies for aligning utility and solar interests across an interrelated set of regulatory and utility functions.
- Year 1: identify innovative practices for incorporating distributed solar photovoltaics (DPV) into planning studies.
- Premise: Realizing the full value of DPV requires accounting for it in planning studies.
- Follow-on Year 2 research will show that adoption of best practices can meaningfully affect planning study results, in terms of resource costs and solar deployment.

Approach

- Comparative analysis and evaluation of recent planning studies, identifying innovative practices, lessons learned, and state-of-the-art tools.

Scope

- Electric infrastructure planning (IRPs, transmission, distribution).
- Focus on the treatment of DPV, with emphasis on how DPV growth is accounted for within planning studies.

Organization of Report

Forecasting quantity of DPV

- Section 3

Robustness of decisions to uncertainty in DPV quantity

- Section 4

Characterize DPV as a **resource option**

- Section 5

Non-dispatchability of DPV

- Section 6

Location-specific factors of DPV

- Section 7

Impact of DPV on **T&D investments**

- Section 8

Avoided losses associated with DPV

- Section 9

Changes with DPV **penetration**

- Section 10

Integration of DPV **across p**lanning forums

- Section 11

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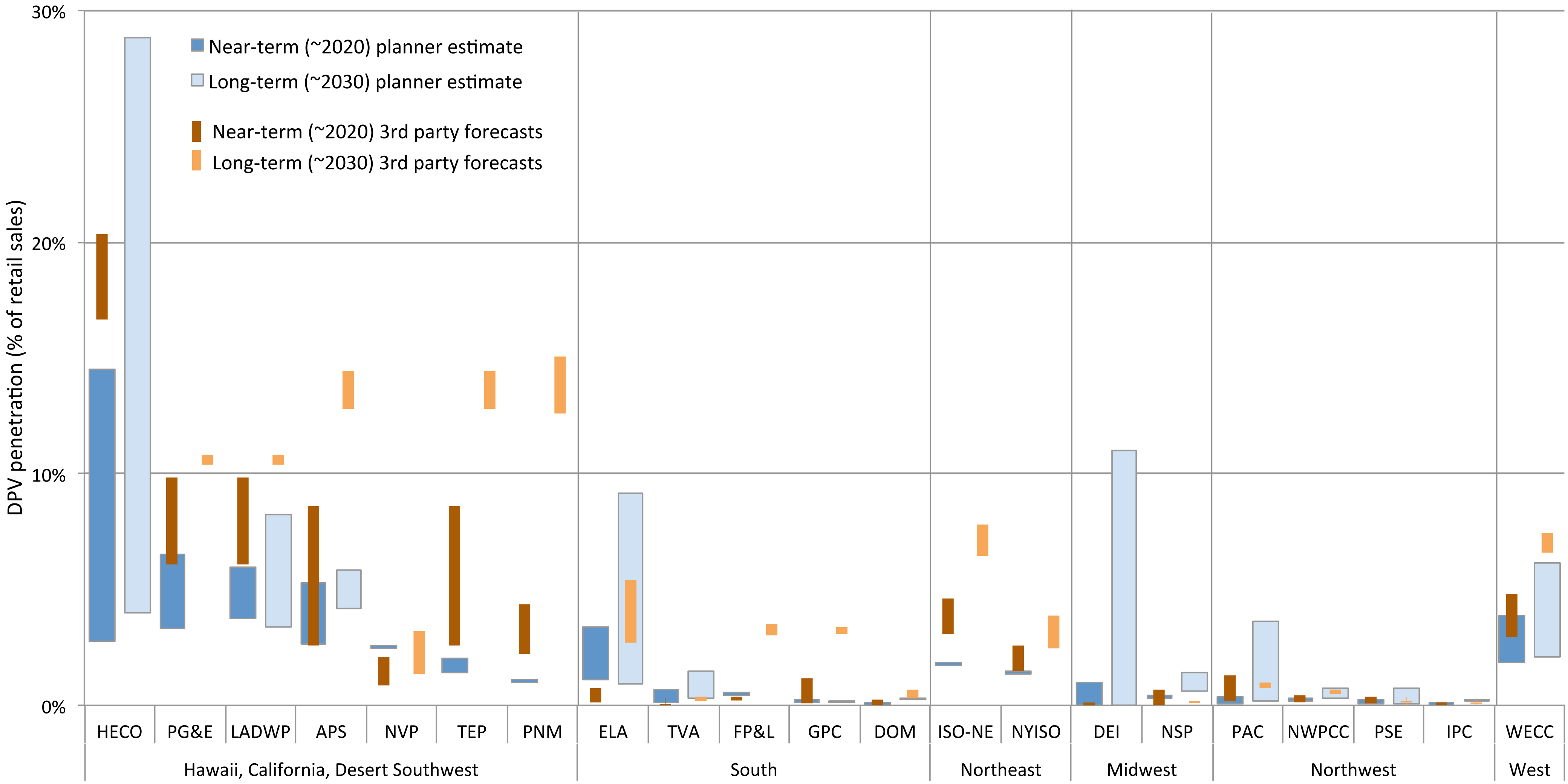
- Section 11

High End of 3rd Party Forecasts Suggests More DPV Than Is Considered By Utilities

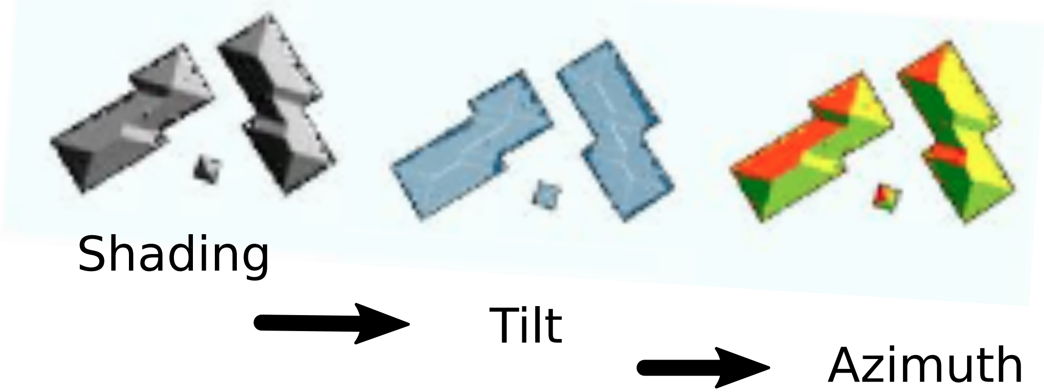


Some Planners Use Customer-adoption Models for DPV Forecasting

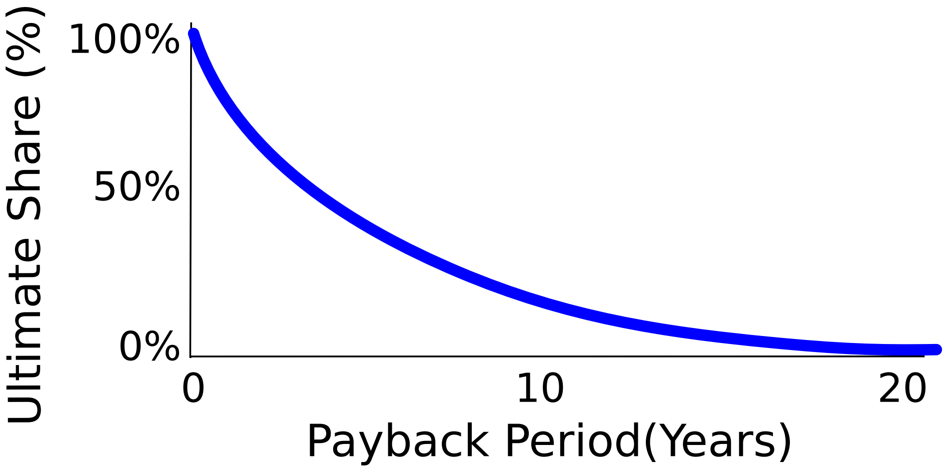
Technical Potential

Willingness-to-adopt

Diffusion



Adapted from: Gagnon et al. 2016



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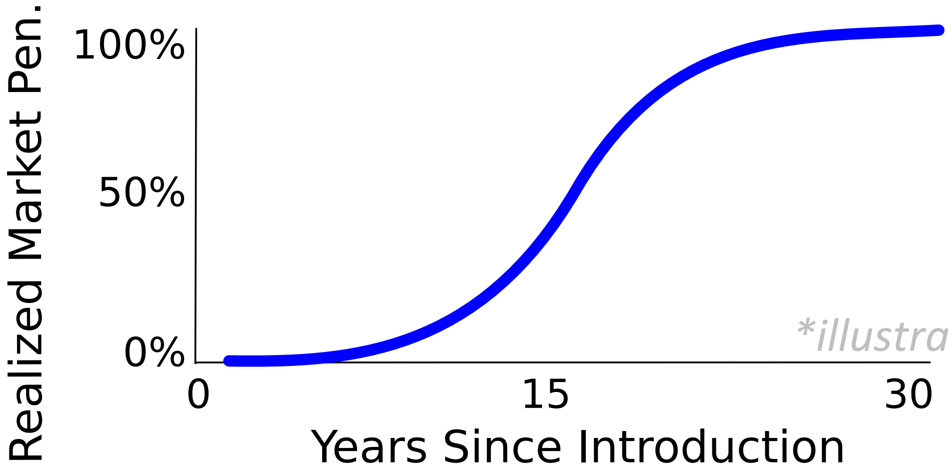
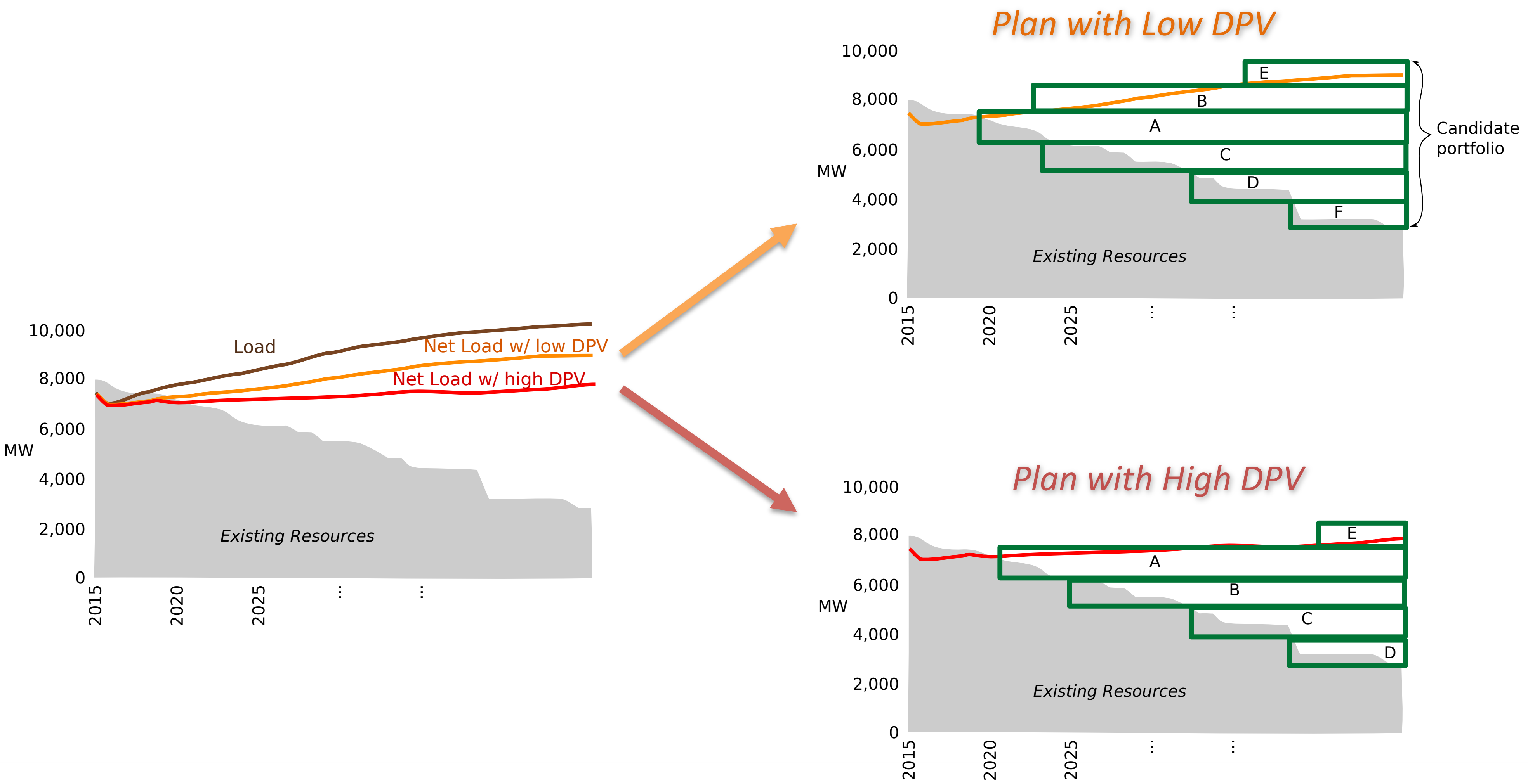


*illustrative

Robustness of Decisions to Uncertainty in DPV Quantity

Forecasts of DPV Adoption are Uncertain → Develop Scenario-Specific Plans



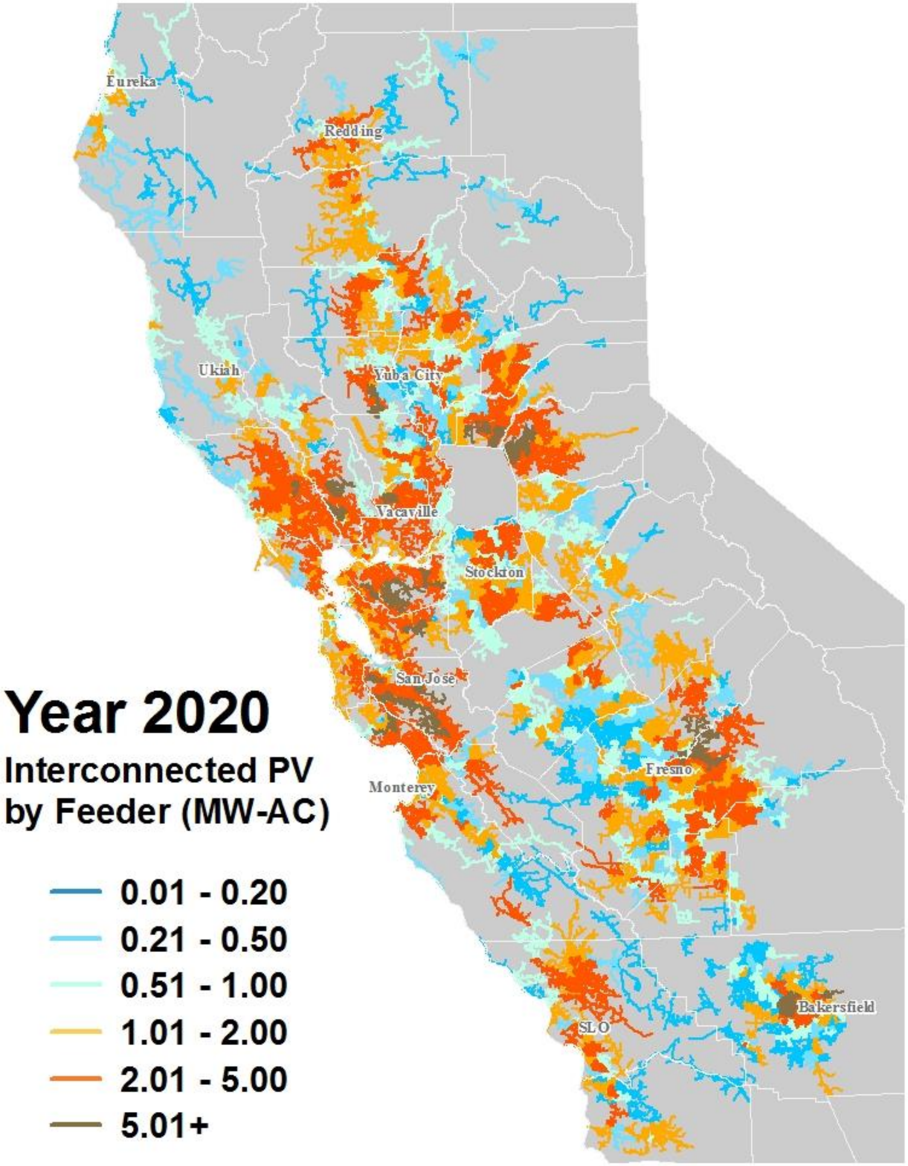
*illustrative

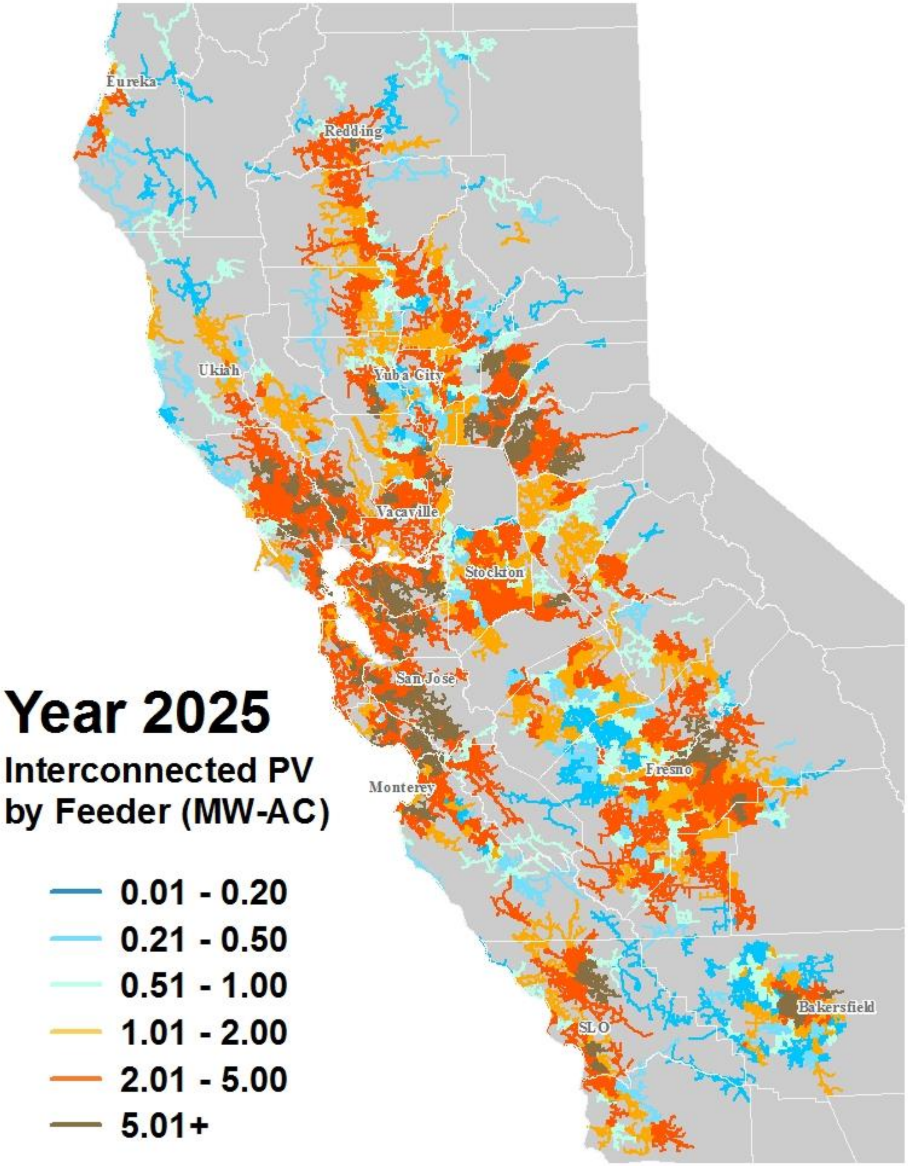
Use Difference In Plans to Identify Trigger Events and Resulting Changes to Plan

Trigger Event	Planning Scenario	Resource Acquisition Strategy	
		Near Term (2015-24)	Long-Term (2025-34)
Higher sustained DG penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Reduce forward contract acquisition • Continue to pursue EE	• *Reduce acquisition of gas-fired resources* • Balance timing of thermal acquisition with forward contracts and EE
Lower sustained DG penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Increase forward contract acquisition (primarily beginning 2024) • Continue to pursue EE	• *Increase acquisition of gas-fired resources* • Balance timing of thermal acquisition with forward contracts and EE

Source: PacifiCorp (2015)

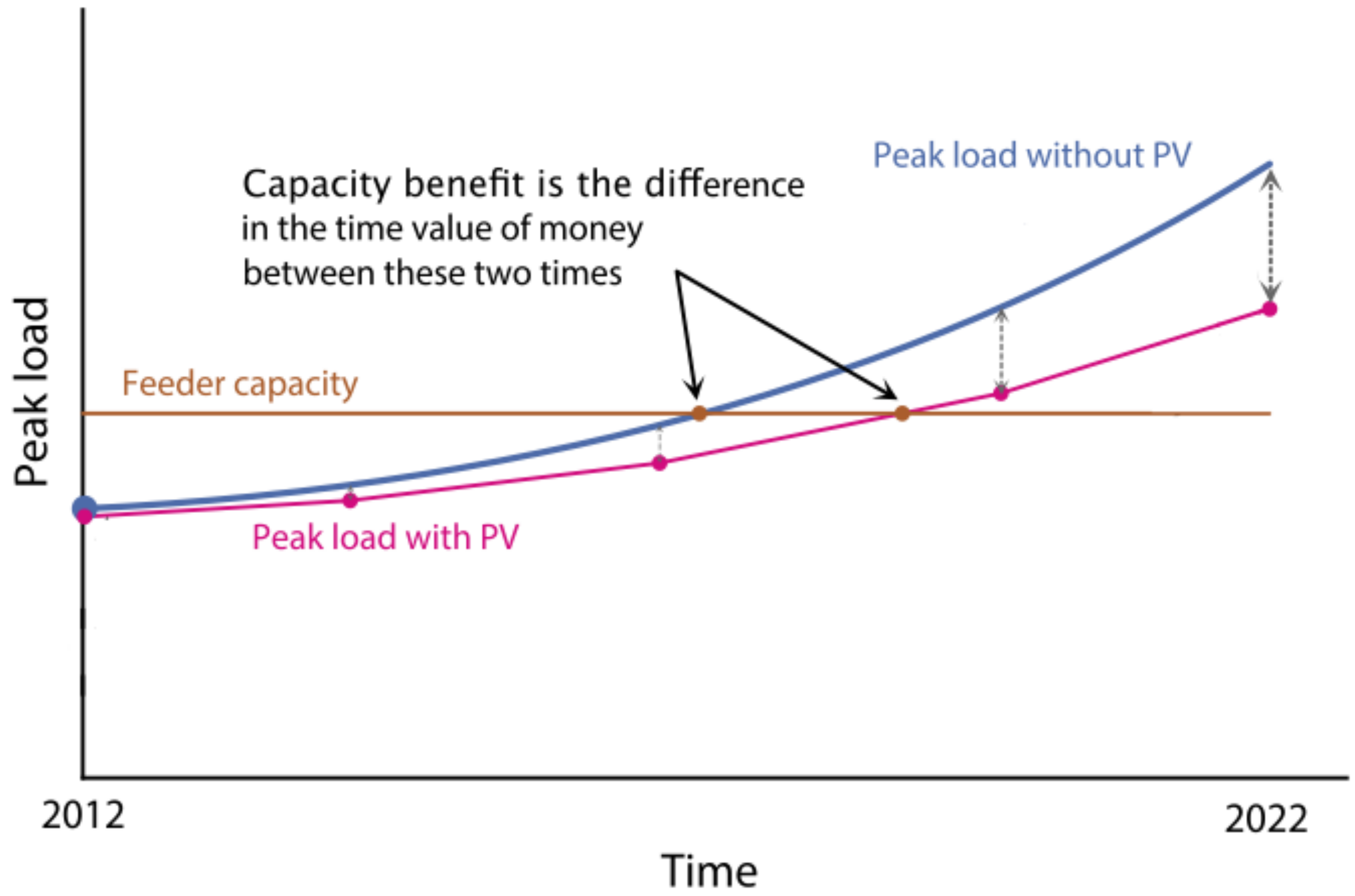
Predicting the Location of DPV Adoption





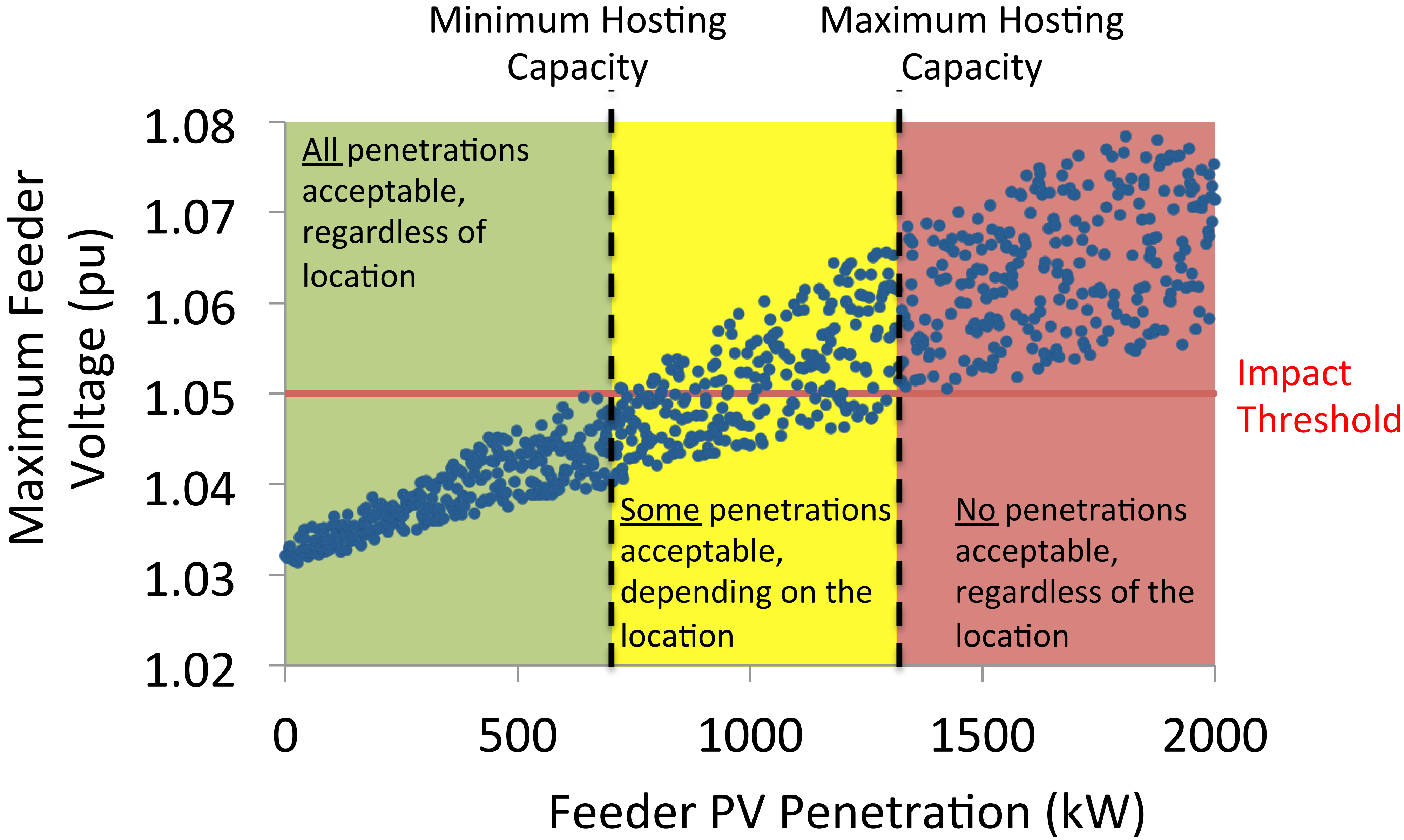
Source: PG&E 2015 DRP

Impact of DPV on T&D Investments: Potential Deferral Value



Source: Adapted from Cohen et al. 2016

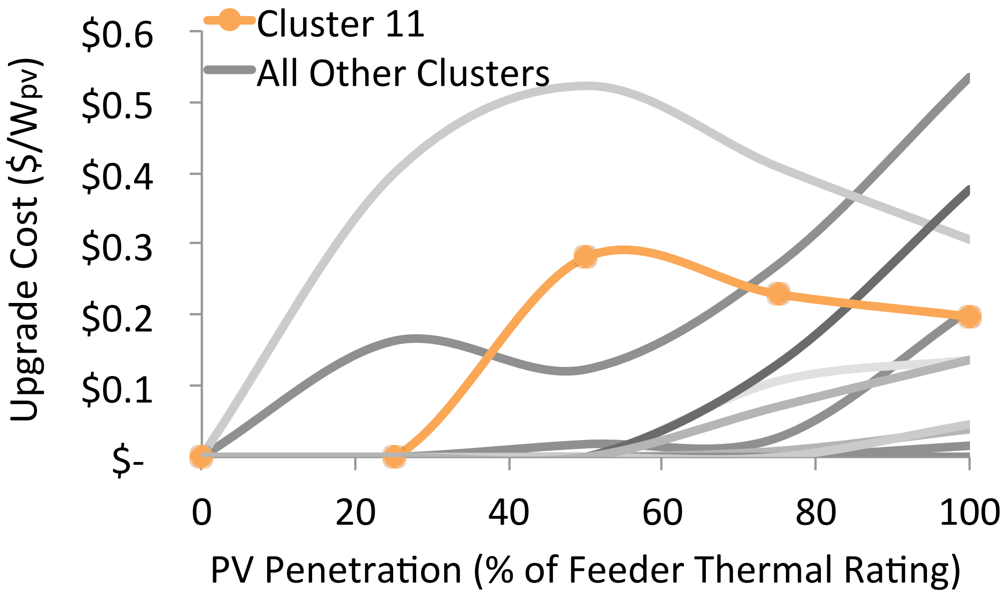
Impact of DPV on T&D Investments: Hosting Capacity Analysis



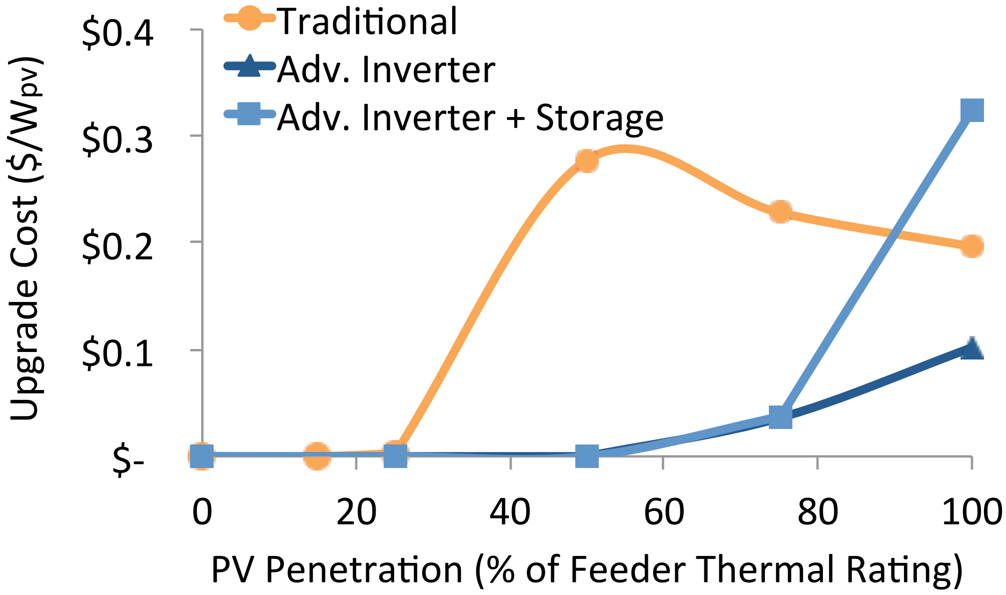
Source: Adapted from EPRI 2015

Impact of DPV on T&D Investments: Proactive Planning for DPV

Costs to Increase the Hosting Capacity of Fourteen Representative Feeders with Traditional Grid Upgrades



Costs to Increase the Hosting Capacity of Cluster 11 Comparing Traditional Grid Upgrades to Emerging Options



Source: Adapted from Navigant 2016

Highlights for Innovative Practices

- **Forecasting:** Customer-adoption modeling for DPV forecasts.
- **Robustness:** Develop scenario-specific plans. Use differences in plans to identify “trigger events” that will result in changes to plan.
- **DPV as a Resource:** Fully characterize DPV as a resource option. Consider in resource, transmission, and distribution planning.
- **Location of DPV:** Forecast location of DPV to improve estimates of the T&D impact and location-specific value of DPV. Use propensity to adopt based on household/customer characteristics.
- **Impacts to T&D:** Include DPV in forecast of peak load for transmission and distribution planning. Use hosting capacity analysis to identify needs for proactive distribution investments.
- **Non-dispatchability:** Use hourly DPV profiles from SAM, CPR, or PVSyst. Calculate contribution to adequacy with ELCC. Use detailed integration studies to investigate sub-hourly challenges and costs.
- **Avoided Losses:** Account for time-varying loss rates.
- **Changes with penetration:** Identify costs and benefits for different tranches of DPV. Consider charging EVs when solar output is high.

Contact Information

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http://emp.lbl.gov/reports/re

Sample of Integrated Resource Plans

Entity	Title and Year
APS	2014 Integrated Resource Plan
CA PUC	Assigned Commissioner's Ruling On Updates To The Planning Assumptions ....
Dominion	2015 Integrated Resource Plan
Duke Energy Carolinas	2014 Integrated Resource Plan
Duke Energy Indiana	2015 Integrated Resource Plan
Entergy Louisiana	2015 Integrated Resource Plan
Florida Power & Light	Ten Year Power Plant Site Plan: 2015-2024
Georgia Power	2016 Integrated Resource Plan
HECO	2013 Integrated Resource Planning Report
Idaho Power	2015 Integrated Resource Plan
LADWP	2014 Integrated Resource Plan
Nevada Power	2015 Integrated Resource Plan
Northern States Power	2015 Resource Plan
NWPCC	7th Conservation and Electric Power Plan
PacifiCorp	2015 Integrated Resource Plan
PNM	2014 Integrated Resource Plan
PSE	2015 Integrated Resource Plan
TEP	2014 Integrated Resource Plan
Tri-State G&T	Draft 2015 Integrated Resource Plan/ Electric Resource Plan
TVA	Integrated Resource Plan - 2015 Final Report

Sample of Transmission Planning Studies

Entity	**Title and Year**
ACC	2014: 8th Biennial Transmission Assessment
CAISO	2015-2016 Transmission Planning Process Unified Plan. Assumptions and Study Plan
ISO-NE	2015 Regional System Plan
NYISO	2015 Load and Capacity Data Report
PJM	2015 Regional Transmission Expansion Plan: Book 2
Tri-state, Black Hills, PSCO	2014: Attachment A: 10-Year Transmission Plan & Appendix B: 20-year
WECC	2013 Interconnection-wide Transmission Plan
WestConnect	WestConnect Regional Transmission Planning Process: 2015 Regional Study Plan

Sample of Distribution Planning Studies

Entity	Title and Year
CA: PG&E	2015: Distribution Resources Plan
CA: SCE	2015: Distribution Resources Plan
CA: SDG&E	2015: Distribution Resources Plan
HECO	2014: Distributed Generation Interconnection Plan
MA: Eversource	2015: Grid Modernization Plan
MA: National Grid	2015: Grid Modernization Plan
NY DPS	2015: Distributed System Implementation Plan Guidance

Modeling and Analyzing the Value of Distributed Energy Resources with (and within) the Bulk Power System: Distributed Locational Marginal Prices (DLMP)

Richard D Tabors, Ph.D.

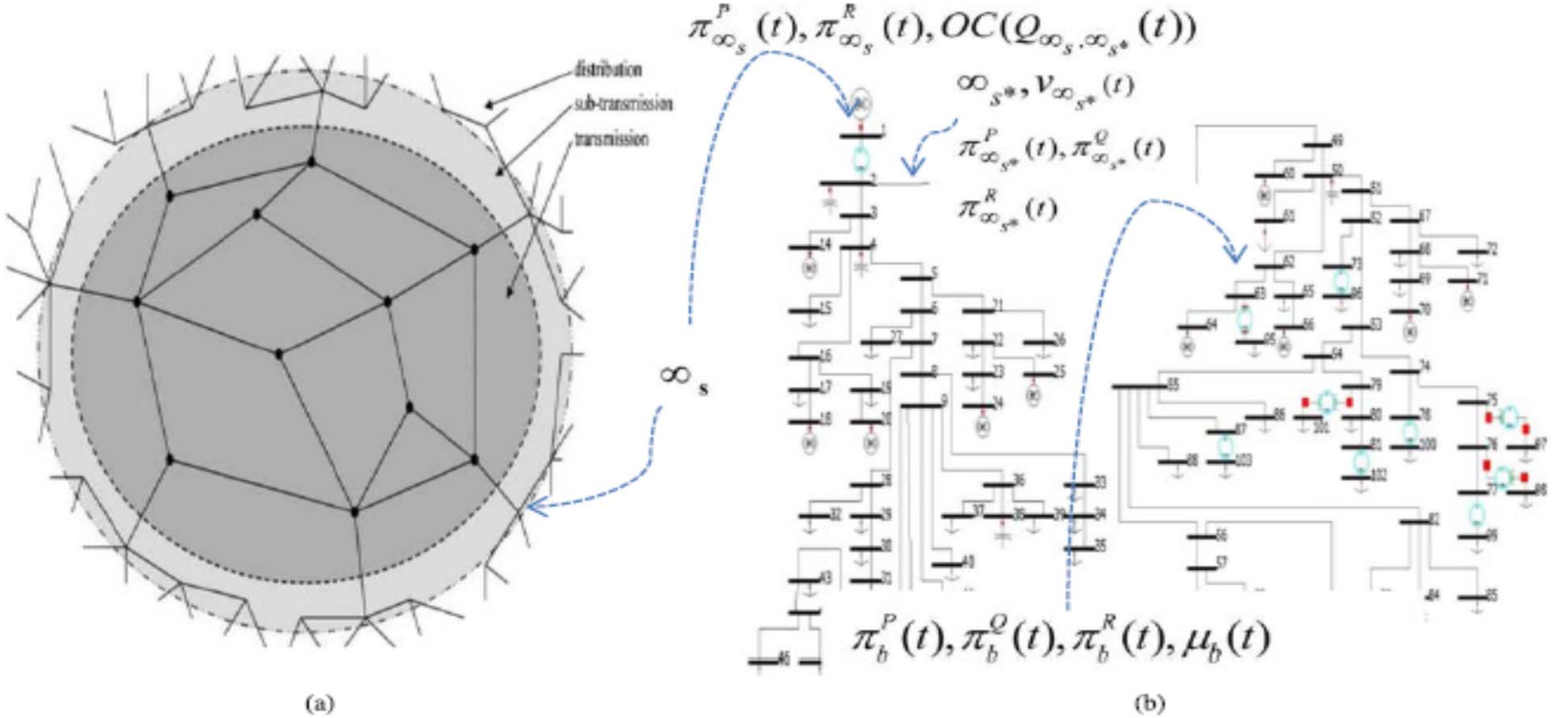
Tabors Caramanis Rudkevich (TCR)

MIT Utility of the Future Project, co-director

NERC Distributed Energy Resources Workshop

August 2, 2016

LMP / DLMP from Transmission to the Meter …



a) Transmission, subtransmission, and distribution schematic. (b) Expanded distribution feeder schematic.

Caramanis, Ntakou, Hogan, Chakrabortty and Shoene "Co-Optimization of Power and Reserves in Dynamic T&D Power Markets with Nondispatchable Renewable Generation and Distributed Energy Resources" Invited Paper, Transactions of the IEEE Vol 104, No 4, April 2016

Core Electric Products from DER (ONLY 3!)

- The 3 Rs
  - Real Energy
  - Reactive Power
  - Reserves
- The 3 Rs require tradeoffs
  - Tradeoff between producing real versus reactive power
  - Tradeoff between committing now to produce real power (now and forward) and being available to provide reserves

See: Tabors Caramanis Rudkevich “White Paper – Developing Competitive Electricity Markets and Pricing Structures” NYSERDA released April 2016. HTTP://www.tcr-us.com/projects.html

The New World of Consumer / Prosumer in the Power System

- MAXIM: Within the new world of DER and ICT all distribution customers (consumers and producers) see an equal economic value to:
  - Consumption (with or without Demand Response)
  - Generation
  - Storage, etc
- The power system's economic value (Price) of ***their*** energy provided or consumed is a function ONLY of:
  - Quantity (*when and where*)
  - NOT of *what* produces the energy or how it is consumed (or not)
- This is the reality of Short Run Marginal Cost (LMP and DLMP)

DLMP is not LMP + D

- What is the difference?
  - DLMP is a **granular, market measure** of the utility's short run marginal cost (SRMC) at the specific ***time*** *and* ***location*** of the core electric product's production or use
  - LMP+D and similar approaches are **average, administrative** estimates of the "avoided cost" of the core electric product. For example LMP (i.e. nodal, or wholesale value, of real energy) plus D (an administratively estimate of average avoided distribution system costs).

Three Market Models of Interaction of DER and the Bulk Power Market

1. Integrated with current "Day Ahead / Real Time" ISO market structures

2. Establishment of market risk-bearing intermediary

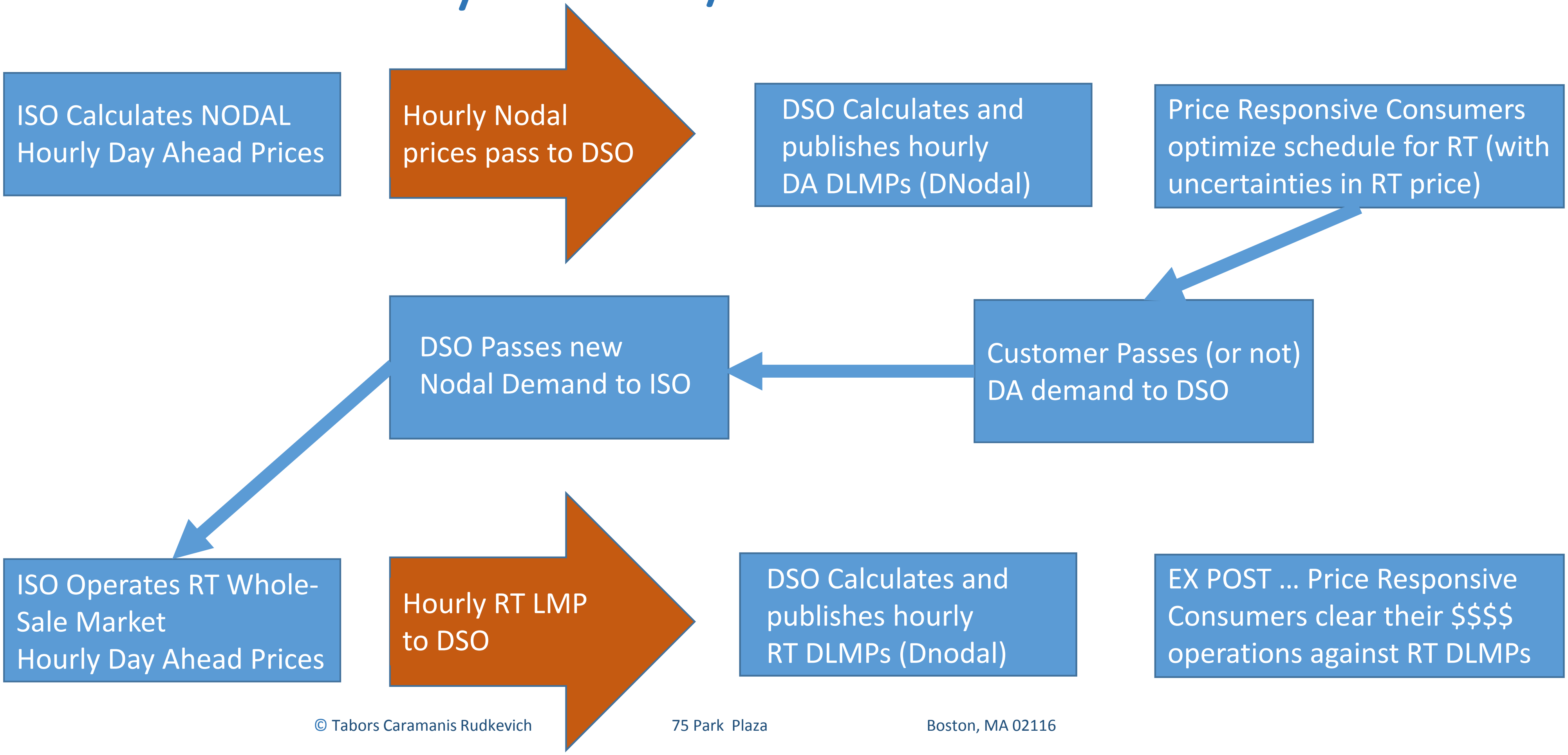
3. Pure market (Bilateral trading) … Platform Economics

Common Market Structure Requirements for Core Electric Products

- **Forward market (*ex ante*)**
  - Continuous, bilateral transactions: location- and time-based bids and offers are matched and price formation occurs
  - Closes immediately prior to the time of simultaneous production and consumption of electricity
  - Forward options contracts enable Distribution Utilities to avoid distribution system investments by obtaining advance commitments from DER to provide location-specific resources (e.g., voltage support, operating reserves)
- **Clearing or Balancing Market (*ex post*)**
  - Needed to clear imbalances between scheduled energy deliveries and actual energy consumed
  - DSOs provide the Platform with relevant data on imbalances, including actual "real time" consumption, production, load flows and distribution system topology
  - Platform runs a mathematical load flow calculation, with the substation LMP as the reference price, to determine a clearing price for energy and reactive power at each traded distribution node.

***Prices** could become more granular in phases, starting at existing, sub-zonal transmission nodes("enhanced LMP" or eLMP) and moving to Distributed LMP (DLMP), as utilities implement interval measurement of real and reactive power at sufficient points to estimate distribution power flows.*

Model 1: Day Ahead / Real Time



ISO Calculates NODAL Hourly Day Ahead Prices

Hourly Nodal prices pass to DSO

DSO Calculates and publishes hourly DA DLMPs (DNodal)

Price Responsive Consumers optimize schedule for RT (with uncertainties in RT price)

Customer Passes (or not) DA demand to DSO

DSO Passes new Nodal Demand to ISO

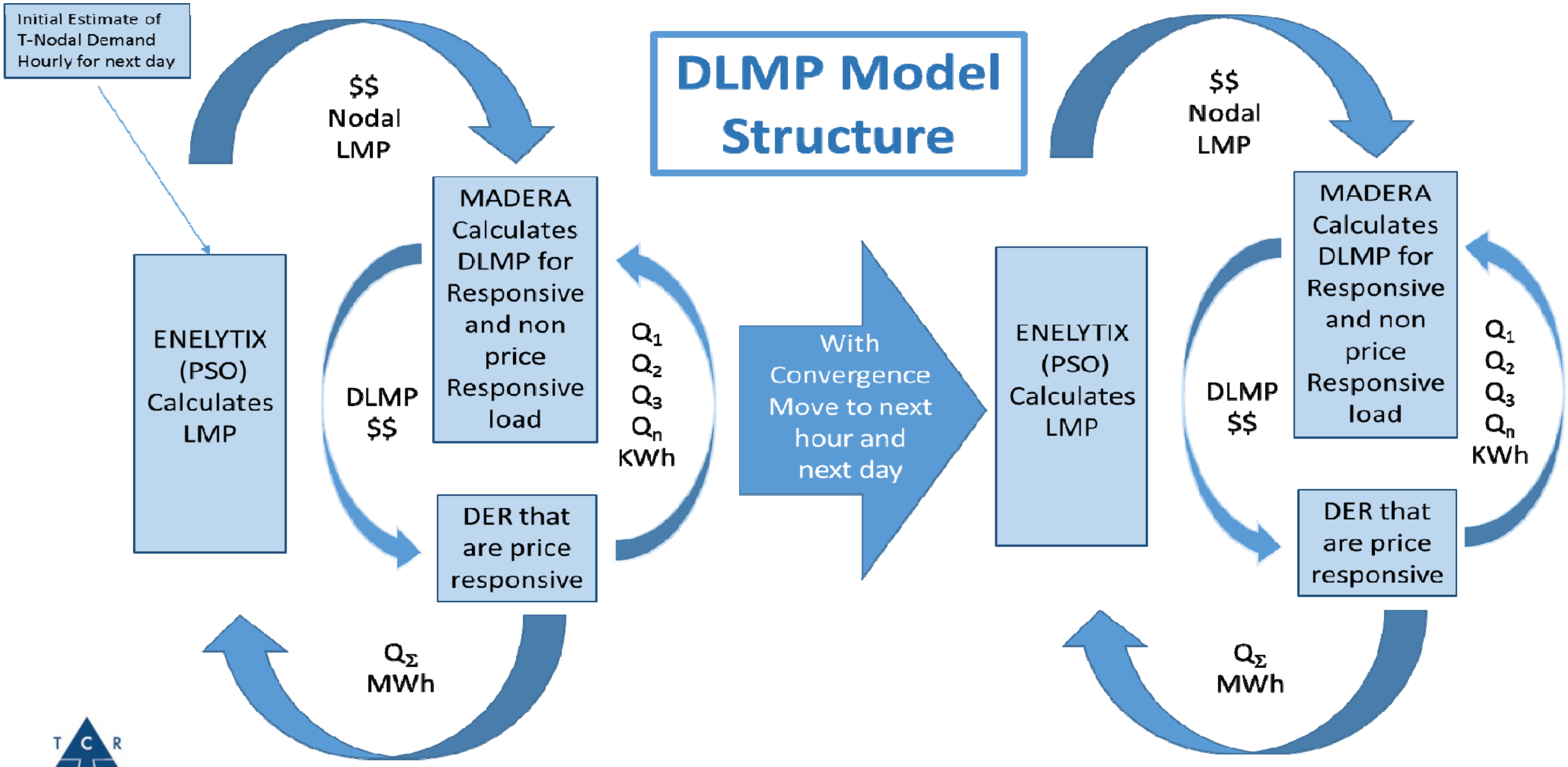
ISO Operates RT Whole-Sale Market Hourly Day Ahead Prices

Hourly RT LMP to DSO

DSO Calculates and publishes hourly RT DLMPs (Dnodal)

EX POST … Price Responsive Consumers clear their $$$$ operations against RT DLMPs

Modeling DLMP Benefits: MADERA$^{\text{TM}}_{\text{pending}}$



Initial Estimate of
T-Nodal Demand
Hourly for next day

DLMP Model Structure

ENELYTIX (PSO) Calculates LMP

$$ Nodal LMP

MADERA Calculates DLMP for Responsive and non price Responsive load

DLMP $$

DER that are price responsive

Q_1
Q_2
Q_3
Q_n
KWh

Q_Σ
MWh

With Convergence Move to next hour and next day

ENELYTIX (PSO) Calculates LMP

$$ Nodal LMP

MADERA Calculates DLMP for Responsive and non price Responsive load

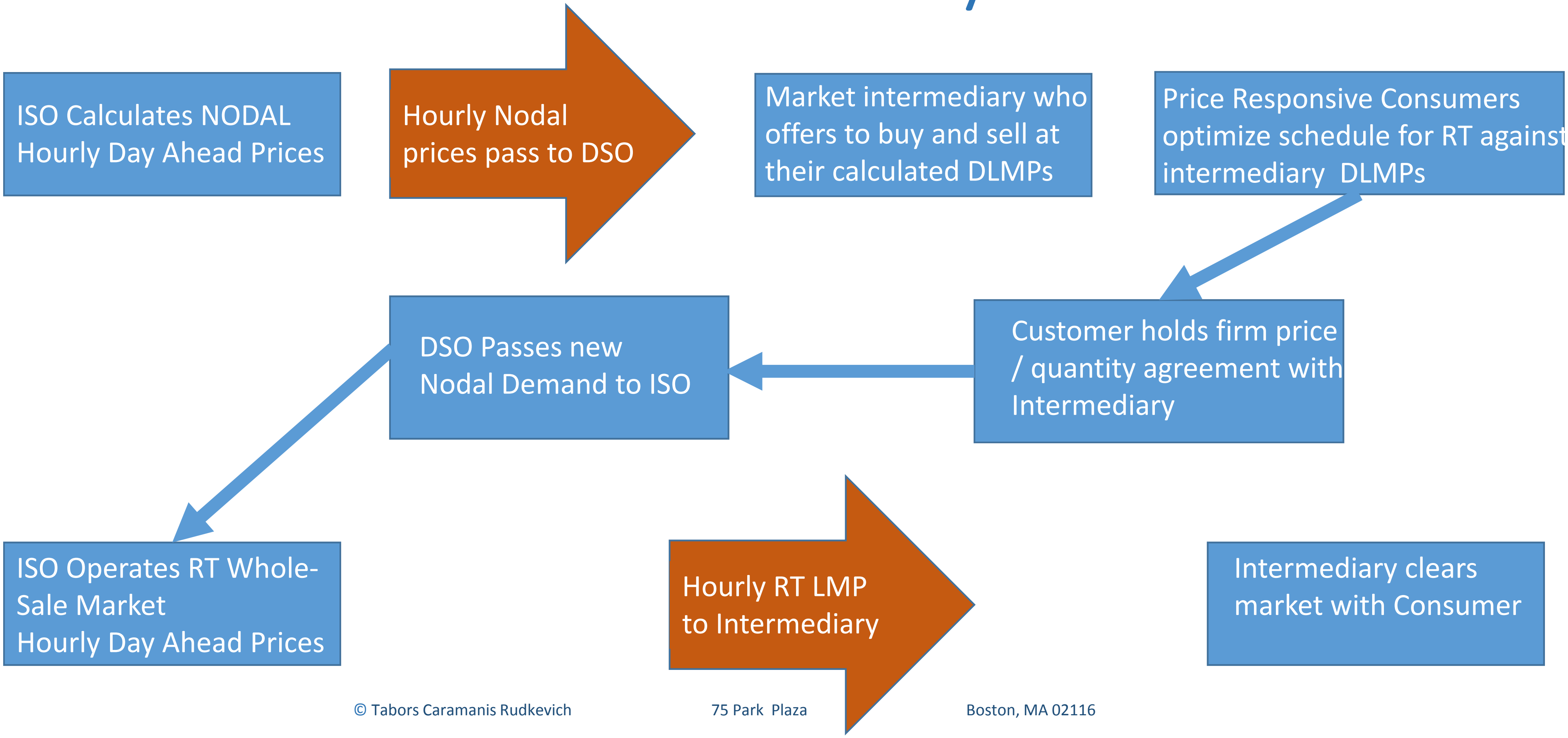
DLMP $$

DER that are price responsive

Q_1
Q_2
Q_3
Q_n
KWh

Q_Σ
MWh

Model 2: Market Intermediary



ISO Calculates NODAL Hourly Day Ahead Prices

Hourly Nodal prices pass to DSO

Market intermediary who offers to buy and sell at their calculated DLMPs

Price Responsive Consumers optimize schedule for RT against intermediary DLMPs

Customer holds firm price / quantity agreement with Intermediary

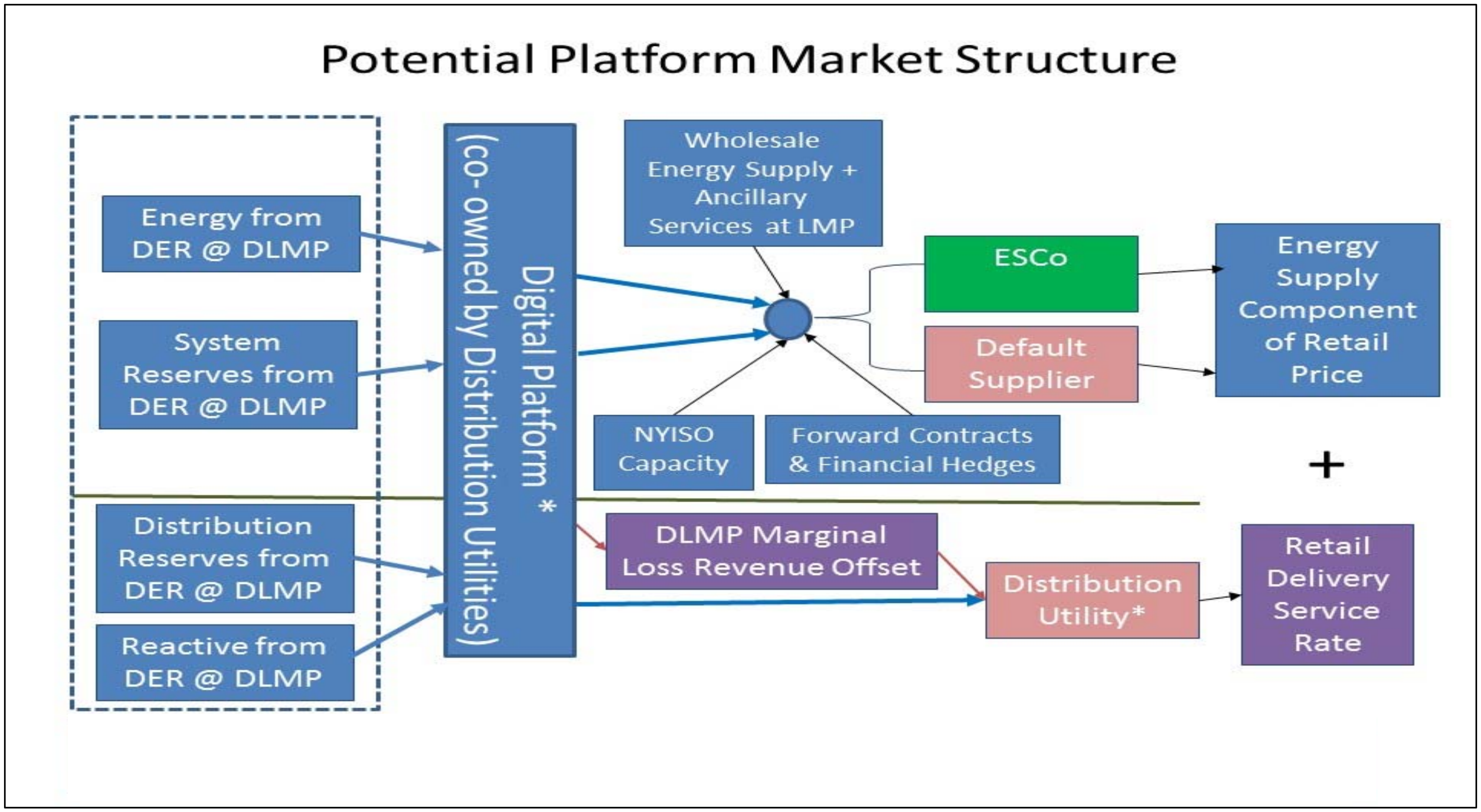
DSO Passes new Nodal Demand to ISO

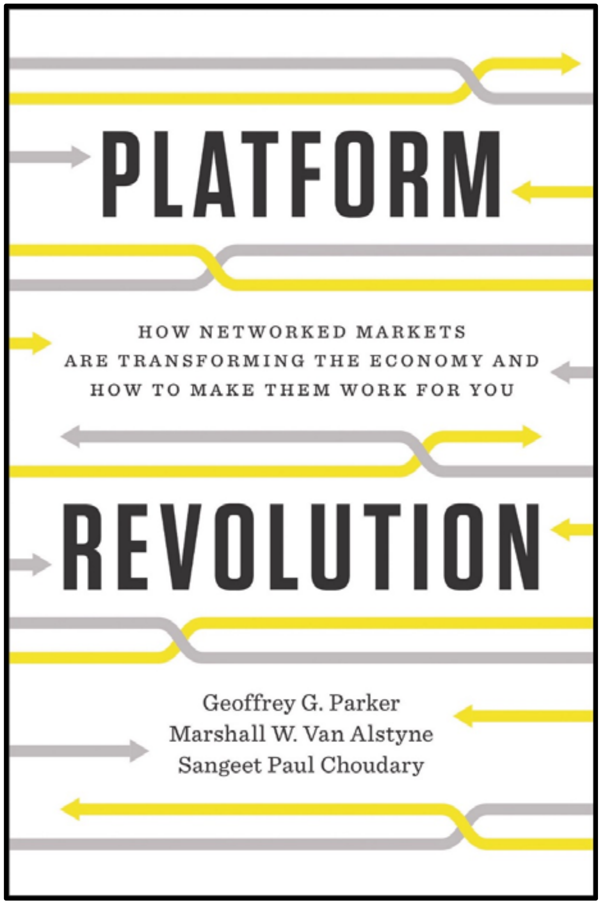
ISO Operates RT Whole-Sale Market
Hourly Day Ahead Prices

Hourly RT LMP to Intermediary

Intermediary clears market with Consumer

Model 3: Platform Market Structure





PLATFORM

HOW NETWORKED MARKETS
ARE TRANSFORMING THE ECONOMY AND
HOW TO MAKE THEM WORK FOR YOU

REVOLUTION

Geoffrey G. Parker
Marshall W. Van Alstyne
Sangeet Paul Choudary

What is an ECONOMIC Platform?

A platform is a business ecosystem that matches producers with consumers, who transact directly with each other using resources provided by the ecosystem itself. The platform ecosystem provides outside parties with easy access to useful products or services through an infrastructure and a set of rules designed to facilitate interactions among users. A platform's overarching purpose is to consummate matches among users and to facilitate the exchange of goods and services, thereby enabling value creation for all participants.

(see: Parker, Van Alstyne and Choudary, ***Platform Revolution***, W.W. Norton & Co. 2016)

The Value Proposition of a DER Platform / Platform Market

- Supports development and operation of a new, competitive market for core electric products, i.e., well-defined products, transparency, multiple buyers and sellers can enter and exit the market freely.
- Enables granular, economically efficient prices that reflect the time- and location-specific value of real energy, reactive power and reserves
- Minimizes transaction costs or friction associated with sale and purchase of core electric products and price discovery
- Expands DER access to markets for their core electric products
    - Real Energy (kWh)
    - Reactive Power (KVARh) in order to maintain voltage within an acceptable band
    - Reserves (a commitment to deliver real or reactive power in the future)
- Animates emergence of new products and services
    - Combinations of services and energy products from competitive suppliers that minimize customer costs
    - Value added services:" price forecasts, analytics, smart technology
- Improves distribution system efficiency: local source of Volt / VAR control

At the End of the Day… What do we need to know about DER???

- In order to assure
  - System Reliability
  - System Security
  - System Resilience
- Balanced against
  - Consumer independence and rights
  - Consumer cost of product and service
- And yes… we need do to pay for the wires that make it all possible

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AUGUST 3, 2016

Distributed Energy Resources Workshop

Voltage and Frequency Performance & Essential Reliability Services Panel

John Simonelli

DIRECTOR OPERATIONS SUPPORT SERVICES

CONSIDERATIONS WHEN INTEGRATING DER

Maintaining adequate voltage on the BES is critical

- Low voltage can propagate
- High voltage can damage equipment

Maintaining adequate voltage on the Distribution System is critical

- Reduce customer outages
- Sustain adequate customer power quality

VOLTAGE AND ITS IMPORTANCE

Adequate voltage is maintained by managing reactive resources

- Loosely defined reactive resources can provide and/or absorb reactive power
  - Dynamic synchronous resources
  - Dynamic non-synchronous resources
  - Static resources
  - HVDC specifically Voltage Source Converters
  - Line compensation
  - Load Power Factor

Key is coordinating these resources between the transmission and distribution systems, need to find the "optimal solution"

CONSIDERATIONS OF REACTIVE NEEDS WHEN INTEGRATING DER

The BES should not impose a reactive burden on the distribution system and conversely the distribution system should not impose a reactive burden on the BES

In a well coordinated system there should not be excessive reactive transfer between the two systems

Key - This must be addressed as part of integration of DER

REACTIVE SUPPORT FROM DER

The proposed definitions of DER cover the spectrum from traditional synchronous resources to inverter based technology to load management

- Understand synchronous machine capability
- Understand load management capability
- Still learning about inverter capabilities (reactive, inertia, frequency response, ride through)

Reactive Support may or may not be provided by all DER

- Physical capability, contractual capability, interconnection capability

Voltage regulation may not be provided by all DER

- Physical capability, contractual capability, interconnection capability

SCENARIO

Assume that all DER are required to be equipped with reactive capability and MUST provide lead/lag Mvars

Operating Characteristics to Consider:

- How does the DER provide lead/lag Mvar?
- Constant power factor?
- Constant Mvar?
- Regulate to a voltage setpoint?
- Provide support only during contingency events?
- What entity determines how this is accomplished?

SUCCESSFUL INTEGRATION DEPENDS ON

How are DER coordinated with the distribution capacitors installed as part of managing load power factor?

How are DER coordinated with distribution voltage regulators?

How are DER coordinated with the step down transformation from the BES?

How should DER reactive/voltage requirements vary over various load levels?

What are some consequences of "missing the boat"?

FOOD FOR THOUGHT

Constant Mvar output:

- *Depending on what set point is selected may support peak load periods but create problems at the lighter load period resulting in excess Mvar on distribution system*
- *This may result in step down transformers and voltage regulators running out of bandwidth to maintain acceptable voltage*
- *End result Mvar flowing up to BES which may exacerbate high voltage conditions on the BES*

FOOD FOR THOUGHT

DER regulates voltage:

- *How is voltage schedule set?*
- *May be adequate to cover a significant number of hours of the year*
- *Potential for negative consequents during those “off nominal” hours*
- *Could result in DER operating in the lag during high voltage conditions or the lead during low voltage conditions*
- *This may result in DER “fighting” other regulation devises like step down transfers and voltage regulators*
- *End result in inappropriate Mvar flows to BES*

MORAL OF THE STORY

Coordinate, coordinate, coordinate…..

The transmission, distribution and DER developers must all sit down at the table and consider multiple scenarios of operation to ensure both distribution and transmission remain robust and reliable

Optimization with a lot more variables added

No one can operate in a silo!

Distributed Energy Resources Workshop

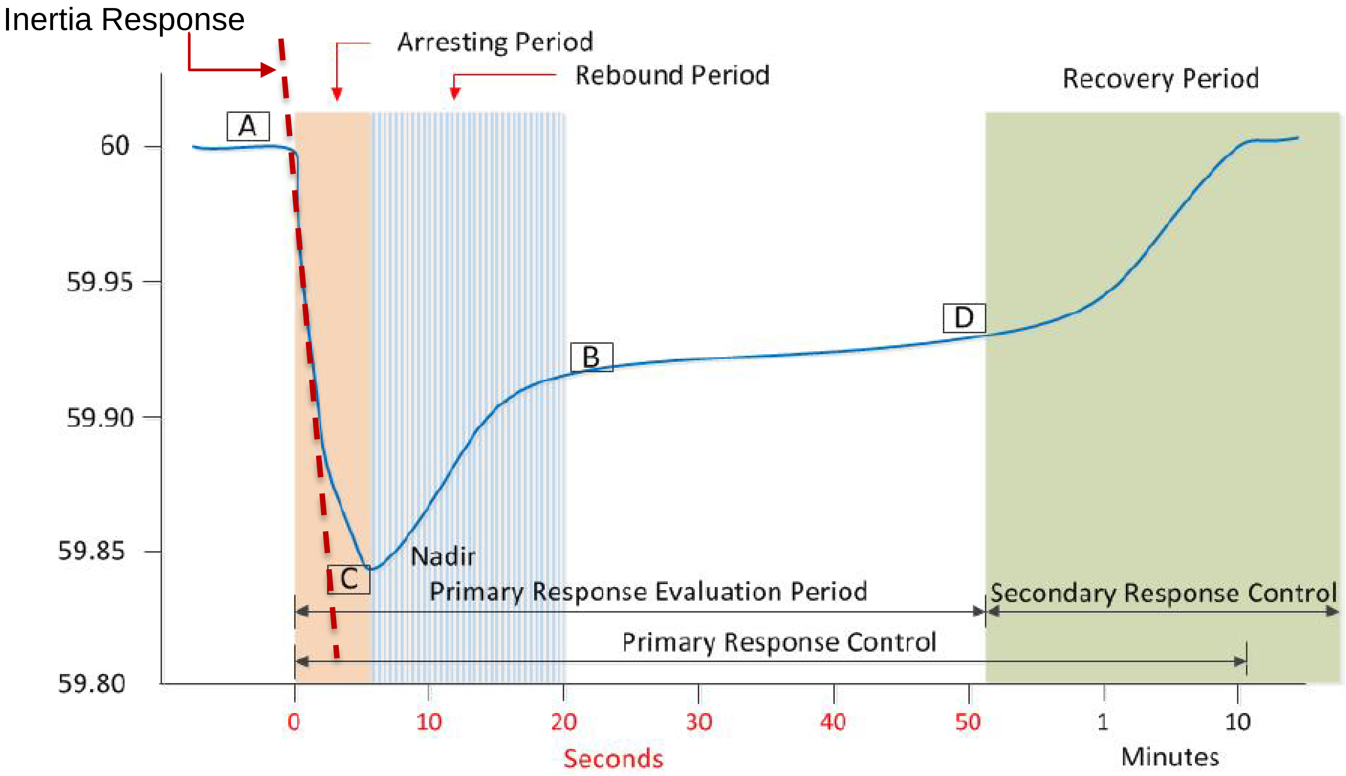
Voltage and Frequency Performance & Essential Reliability Services

Julia Matevosyan
Lead Electrical Engineer
Resource Adequacy
ERCOT

Frequency and its Importance

- Electric frequency is an indicator of the balance between generation and load
- System frequency needs to be maintained within a narrow range around 60 Hz (in North America)
- Prolonged operation outside this frequency range can damage equipment connected to a system and lead to blackouts

Frequency Excursion and Recovery



Frequency Support Measures

- Frequency support is essential to system reliability

- Traditionally, synchronous generators interconnected to the bulk supply system have provided frequency support functions (inertial response, primary and secondary response)

- The technology has been developed in the recent past for some of these functions to be provided by load resources as well as non-synchronous generation resources interconnected to the BES

- It is critical that adequate frequency support is maintained as the DER penetration in the generation mix increases

Possible Impacts of Integrating DER on Frequency Support Needs

Inertial Response:

- Synchronous DER provide inertial response in the same manner as synchronous generators interconnected to BES
- Non-synchronous DER (wind, PV, batteries, etc.) do not contribute to system inertia, while also displacing synchronous generation in the unit commitment

Consequence: lower system inertia, need for faster frequency response and/or higher reserves

Primary Frequency Response (PFR):

- Currently no requirement for DER to provide PFR, while DER are displacing synchronous generation in unit commitment

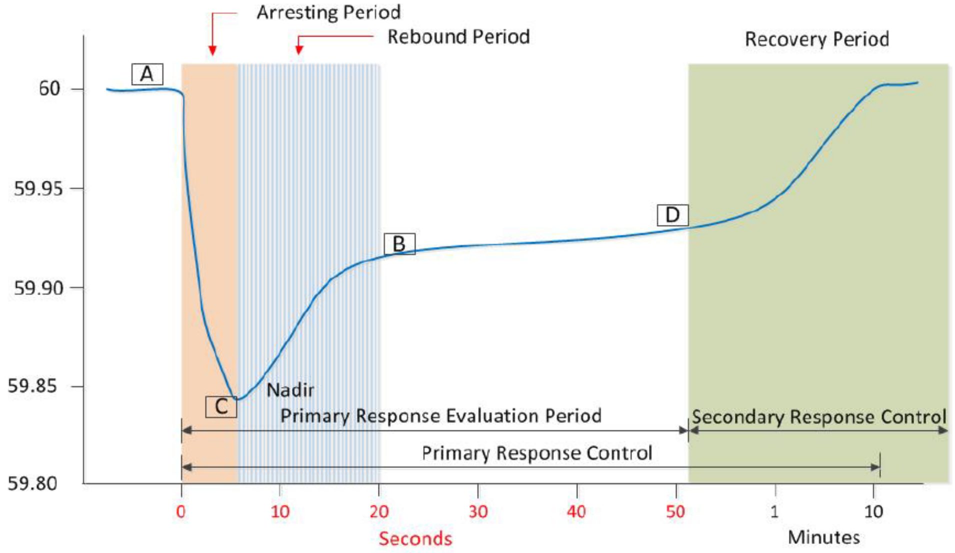
Consequence: less PFR-capable resources available, deteriorating frequency performance

Possible Impacts of Integrating DER on Frequency Support Needs

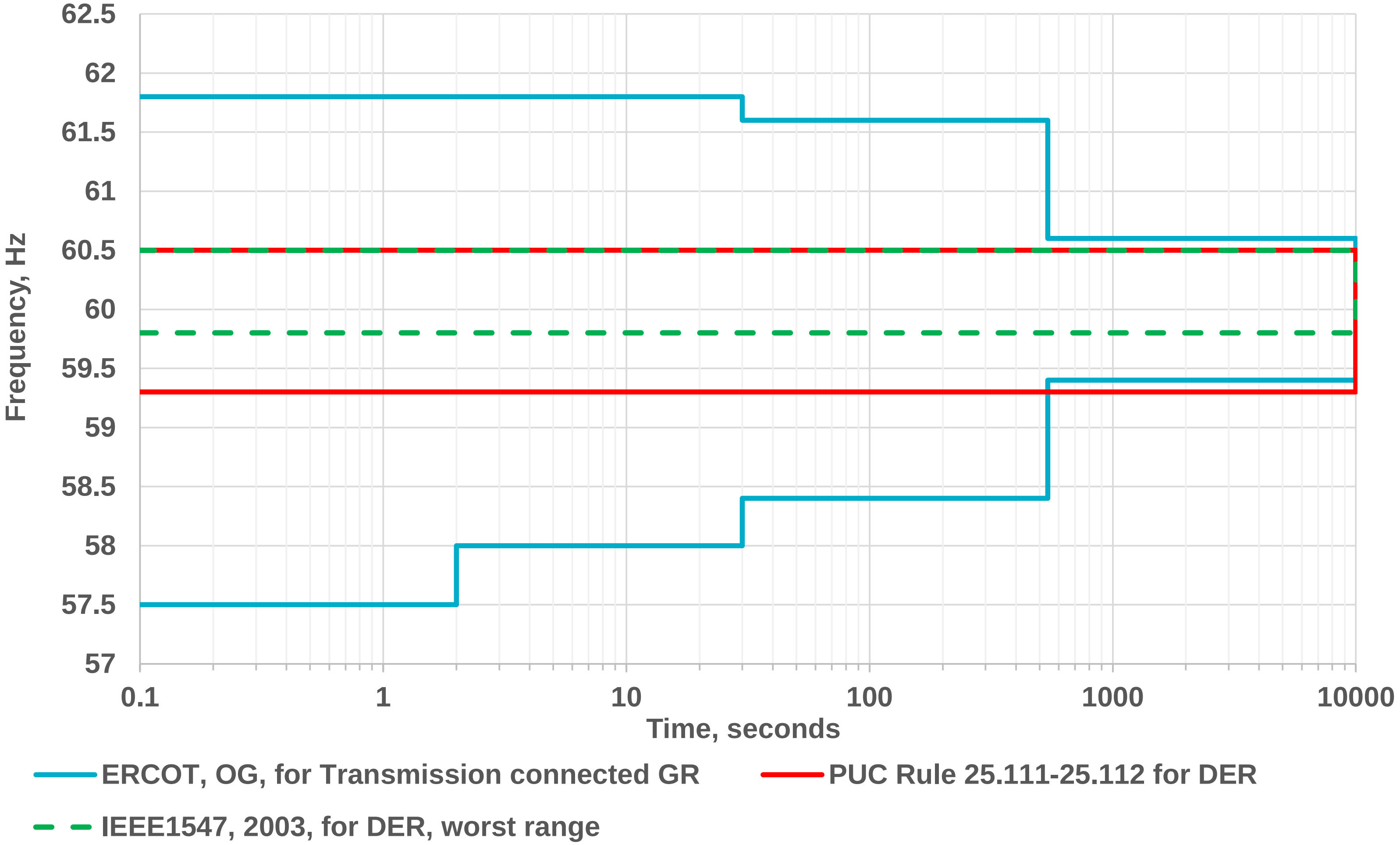
Low/High frequency ride-through:

- DER are required/allowed to disconnect at high or low system frequency

Consequence: Frequency excursions may lead to additional DER tripping, lower frequency nadir, slow recovery, possibly first swing instability. Need for more reserves.



Frequency Ride-Through, PUCT Rule vs IEEE1547 (2003) vs ERCOT Operating Guides



Need for timely, thought-through interconnection requirements, example of Germany

- Since 2006, DER connected to low voltage (LV) in Germany were required to be switched off immediately at 50.2 Hz (for 50 Hz system)
- Between 2006 and 2011, about 12 GW of new PVs connected at LV level
- In the worst case scenario about 9 GW of PV systems could trip at 50.2 Hz
- European interconnected system is only designed for 3 GW trip
- Retrofitting costs were estimated at $84-229 million
- We need to learn from others experiences to get ahead of the problem

Frequency Support from DER

Inertial Response:

- Synchronous DER can provide inertial response.
- Certain types of DER (storage, load resources, etc.) can potentially provide fast frequency response to supplement inertial response.

Primary frequency response:

- Solar and wind DER can provide PFR at over-frequency by automatically curtailing output during an event.
- To provide PFR at under-frequency, power output would need to be curtailed at all times below what is potentially available.

Low/High frequency ride-through:

- Provided that requirements are put in place in a timely manner, DER can be designed to ride-through high/low frequency events.

Requirements for Successful Integration of DER

- Timely and carefully designed interconnection requirements for frequency support and low/high frequency ride-through
- Processes to ensure compliance with the requirements
- Data exchange between DERs/DSOs/ISOs that allow adequate modelling for BES frequency studies and dimensioning of reserves for sufficient frequency support
- Operational visibility and controllability

Questions

Julia Matevosyan

jmatevosjana@ercot.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Distributed Energy Resources (DER) and Essential Reliability Services

Voltage and Frequency Ride-Trough

Operating Reserves Concept

IEEE 1547

Rich Hydzik, Avista Utilities
August 3, 2016

RELIABILITY | ACCOUNTABILITY

Distributed Energy Resources – Concerns Ensue

- In 2015, the Essential Reliability Services Task Force identified DER as potential challenge to BPS Reliability
- CAISO
  - 4900 MW Behind the Meter DER today
  - 9500 MW expected 2020
  - CAISO 2015 forecast peak was 49,400 MW
- 2016 - DER Task Force (DERTF) formed

Initial Concern

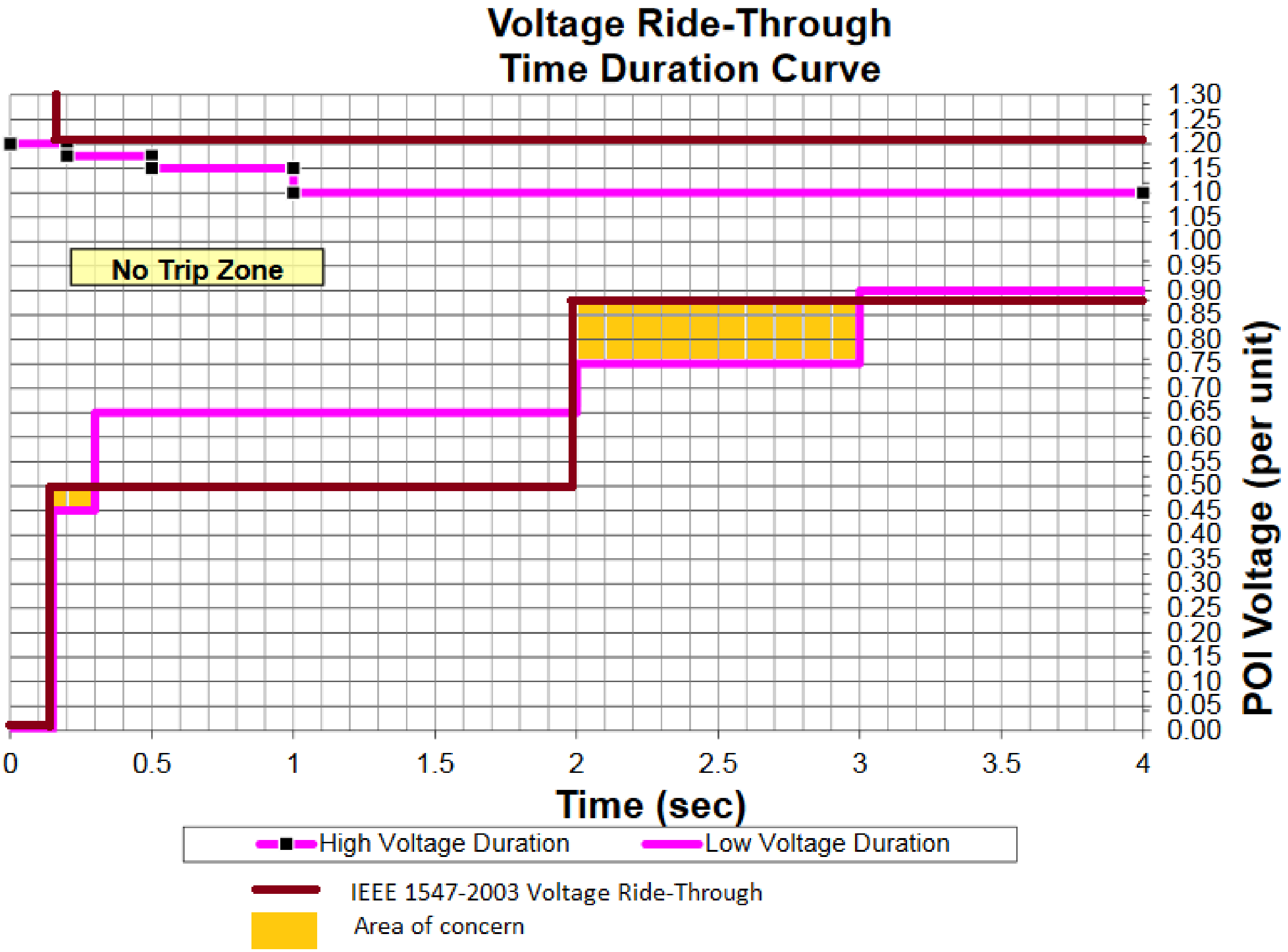
- Largest credible contingencies in WECC
  - 2 Palo Verde Units 2800 MW – 59.65 Hz nadir
    - Limiting outage for COI rating
  - Pacific DC RAS 3000 MW – 59.65Hz nadir
- How do the DER's perform under these conditions?
- DER dropping off will significantly increase load exacerbating a frequency excursion
- How do DER's coordinate with UFLS schemes?

IEEE 1547 Voltage Separation Points

- Voltage - < 30 kW
    - V < 0.50 pu – 0.16 seconds
    - 0.50 pu =< V < 0.88 pu – 2.0 seconds
    - 0.88 pu =< V < 1.10 pu – run continuously
    - 1.10 =< V < 1.20 pu – 1.0 seconds
    - V >= 1.20 pu – 0.16 seconds
    - > 30 kW tripping points are field adjustable

PRC-024-2 Voltage Ride-Through and IEEE 1547 < 30 kW

PRC-024— Attachment 2



IEEE 1547 Frequency Separation Points

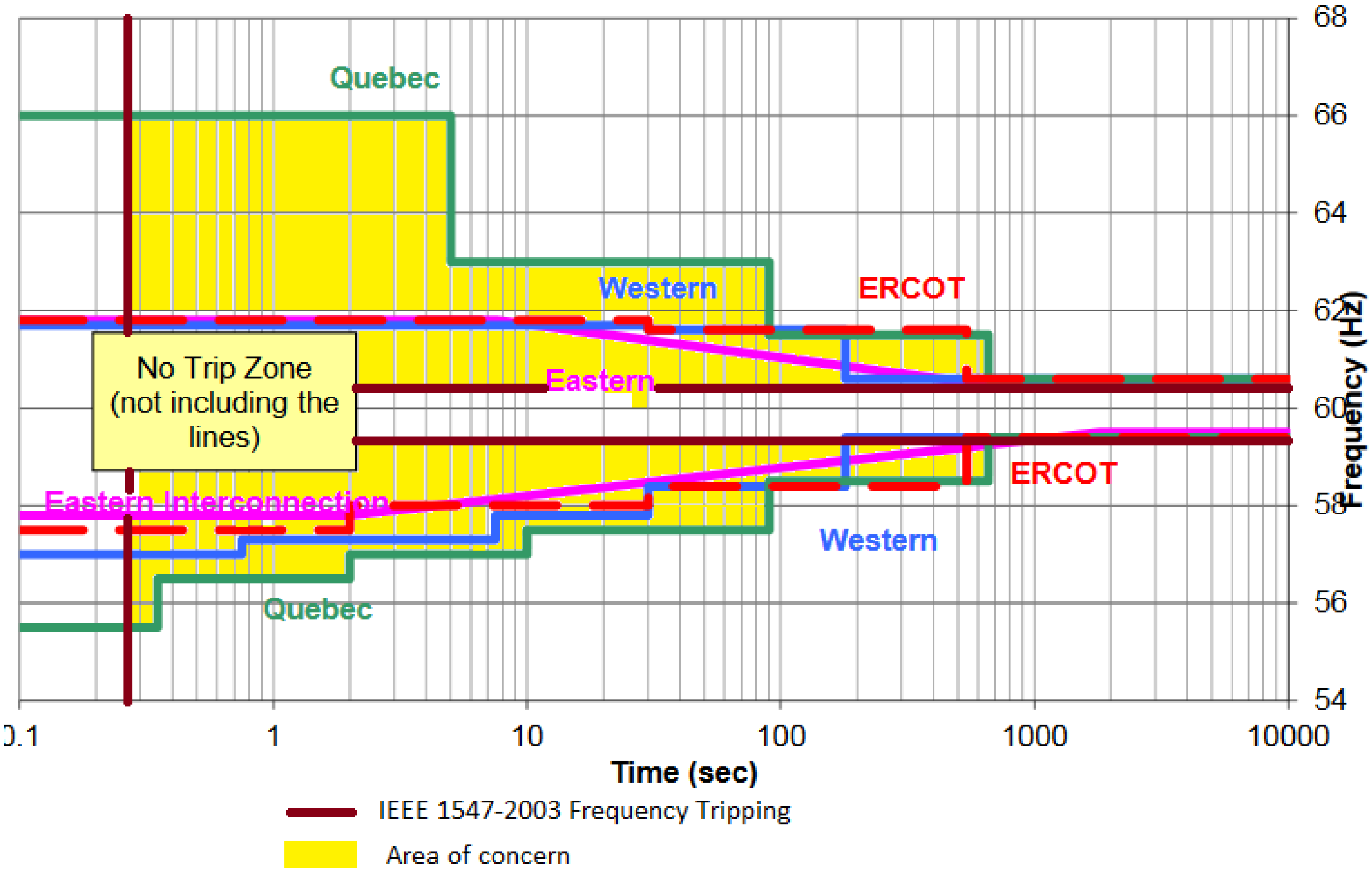
- Frequency

DER Size	Frequency Range (Hz)	Clearing Times (sec)
=< 30 kW	> 60.5	0.16
	< 59.3	0.16
> 30 kW	> 60.5	0.16
	< 59.8 – 57.0 adjustable	0.16 – 300 adjustable
	< 57.0	0.16

NERC PRC-024-2 Frequency Ride Through and IEEE 1547 < 30 kW

PRC-024 — Attachment 1

OFF NOMINAL FREQUENCY CAPABILITY CURVE



Operational Concerns

- MSSC Calculations
  - DER is not considered
- Loss of DER for faults
  - Fault durations longer than 0.16 seconds (Zone 2, Ground Time)
  - DER will separate increasing apparent load
- Loss of DER for frequency excursions
  - DER will separate at 59.3 Hz
  - WECC Off-Nominal Frequency Plan begins dropping at 59.5 Hz (SILT)
  - DER will be separating at 59.3 Hz
    - Adds load to the system
    - Contributes to declining frequency
  - Continuous operation range is probably adequate (59.3 Hz to 60.5 Hz)

Operational Concerns

- Lack of visibility of DER
  - DER and load are netted for Balancing Authority load
- Passive nature of DER
  - Non-dispatchable
  - Operates independently
- Present Operations and Planning Models net DER and load

Work Going Forward

- Models and metering at distribution need to address
    - Load
    - Generation
- IEEE 1547 draft coordinates with PRC-024-2
    - Voltage and frequency ride-through similar to BES requirements
- IEEE 1547 will likely include active features
    - Voltage control
    - Governor type action
- Contingency Reserves for DER?
    - Not addressed under today’s rules
    - Should it be?

Questions and Answers

Essential Reliability Services and System Operations - A Focus on General Principles

Mark Ahlstrom
NextEra Energy Resources & UVIG Board of Directors
NERC Distributed Energy Resources Workshop
August 3, 2016

Utility Variable-Generation Integration Group
Charting the Future of Wind and Solar Power Integration and Operations

UVIG

Learning from Experience

Lessons from the bulk power system:

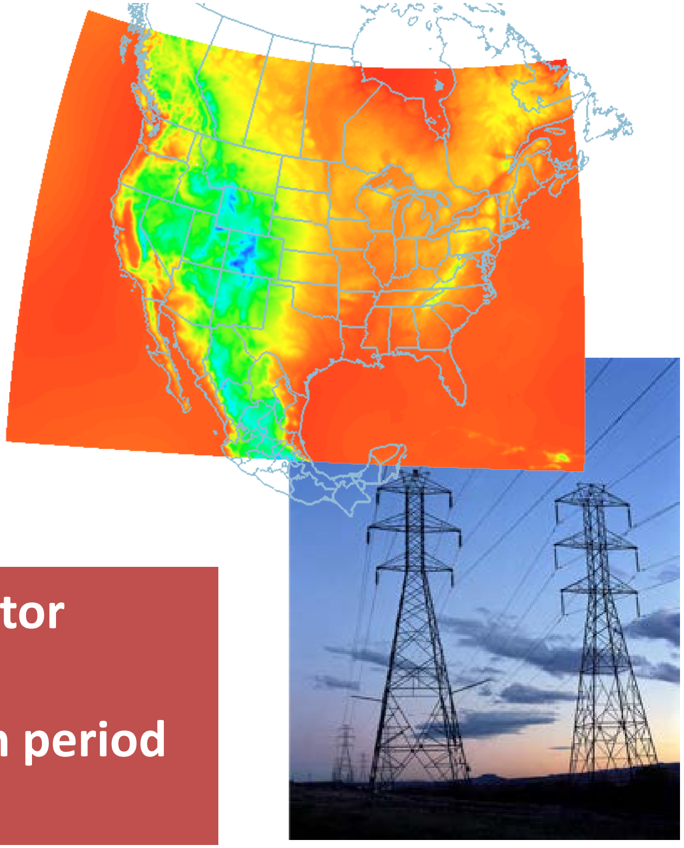
- A “grid code” is a great start (equipment capabilities and modeling)
- Reliability requires coordinated responses (both automatic and directed)
- Controllable loads are just as useful as generators
- All entities must play their part - no one is immune to change
  - New resources must contribute, but they cannot be solely responsible for the system evolution that is necessary
  - Transmission and distribution companies must be very active participants
- Approaches to operations, system design and market design will continue to evolve.. and there are more options than you may think!

Unit Commitment and Dispatch

Unit commitment and dispatch process is the cornerstone of power grid operations

Co-optimizes the constraints of demand, resources, reserves, ramping, etc.,
to satisfy real time needs

“Dispatchable” does not mean being able to provide any desired amount of power at any specified time



Dispatch is not arbitrarily telling a generator what to produce…
It is knowing what is available for the dispatch period and optimizing the system as a whole

Dispatchable - What does it mean?

Various usages are in common practice:

- "Predictable capacity"
  - Example: *"My nuclear units provide dispatchable baseload energy."*
- "Adjustable and following a dispatch setpoint from the system operator"
  - Example: *"Most wind plants are now dispatchable."*

Arguably, both are true in a sense, but the second is more useful when it comes to balancing demand and generation in real time

Dispatchable - What are the implications?

- Does the timeframe of interest matter?
  - Conventional units can trip instantly
    - But this is addressed with contingency reserves
  - Wind power, solar power and load vary with the weather
    - But they are quite predicable for the coming minutes, especially over an area

- Does dispatchable mean that you will be curtailed more?
  - It depends… lowest marginal cost resources will be used almost all the time
  - Reliability/cost differences between “almost always” and “always” are large

- Why are the reliability and cost differences large?
  - Designing for “worst case” versus “common case” is a huge difference

- To most economically maximize the penetration of any given resource, that resource must be willing to accept some level of curtailment

The Technology Trend: Just-in-time Production

Today's information, communications and logistics abilities promote:

- Smart, communicating devices and agents
- Negotiating in real time for the resources that you need
- Simultaneously fine-tuning many parts of the system to balance operations
- Reducing inventories

We do some of this for power today, but in relatively simple ways:

- Off-peak pricing (Xcel “dispatches” my cabin’s electric heat every night)
- Demand side management (HVAC, pool pumps, interruptable loads)
- Demand response

We will move toward more dynamic optimization of load and generation, and this will reduce the necessary amounts of ancillary services and essential reliability services from traditional sources

Many Possible Paths Forward

Abstraction and aggregation are useful, but must fit the problem

- Physics of some problems are local in nature (as are some DER values)
- The local nature introduces complexity for aggregators, locational pricing, level of control, regulation or market power concerns, etc.

DER must participate to achieve reliable and economic solutions

- Grid operation is a complex system of interacting optimization problems
- Many possible approaches and engineering choices to be considered!

Blurring lines of transmission/distribution and generation/load

- See July/Aug 2016 IEEE Power & Energy Magazine article by Perez-Arriaga: *The Transmission of the Future: The Impact of Distributed Energy Resources on the Network*

It’s a great time to be an engineer!

Discussion

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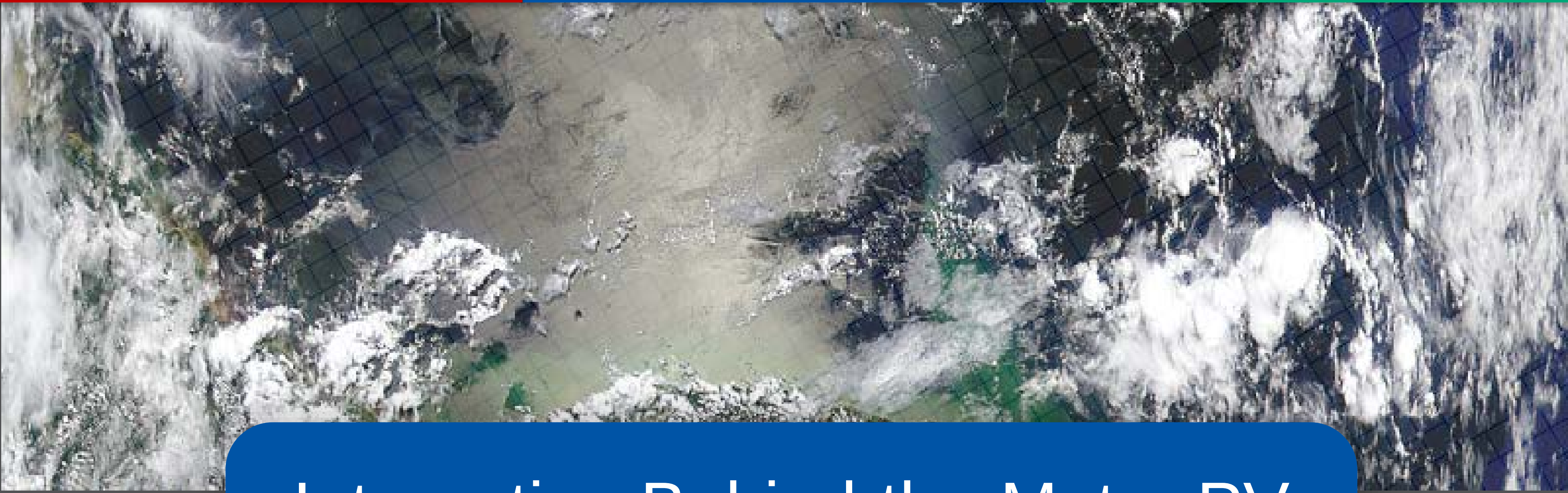
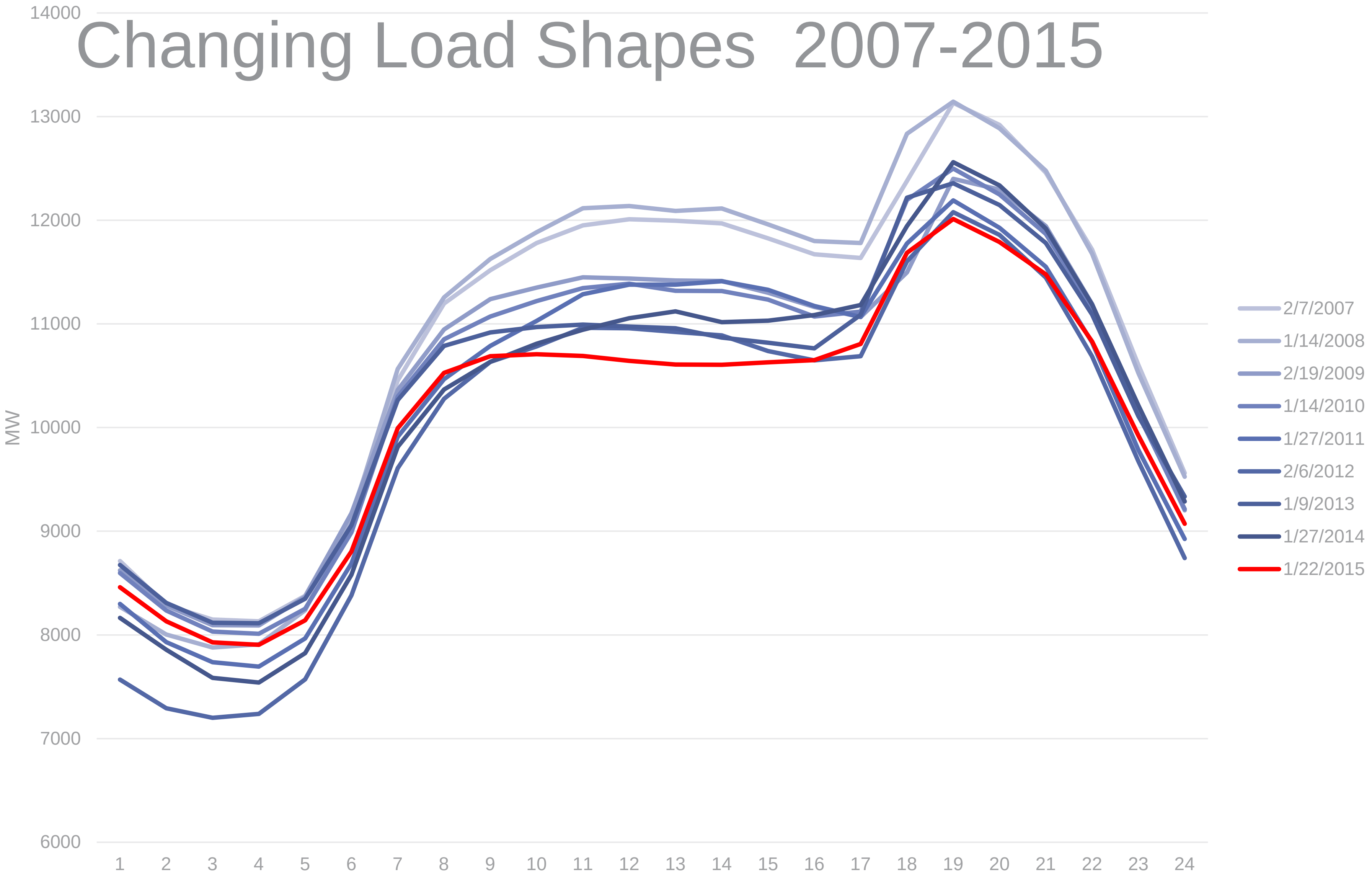


Integrating Behind-the-Meter PV Fleet Forecasts into Utility Grid System Operations

Dr. Thomas Hoff
Clean Power Research
tomhoff@cleanpower.com
Wednesday, August 3, 2016

Clean Power Research®

Changing Load Shapes 2007-2015



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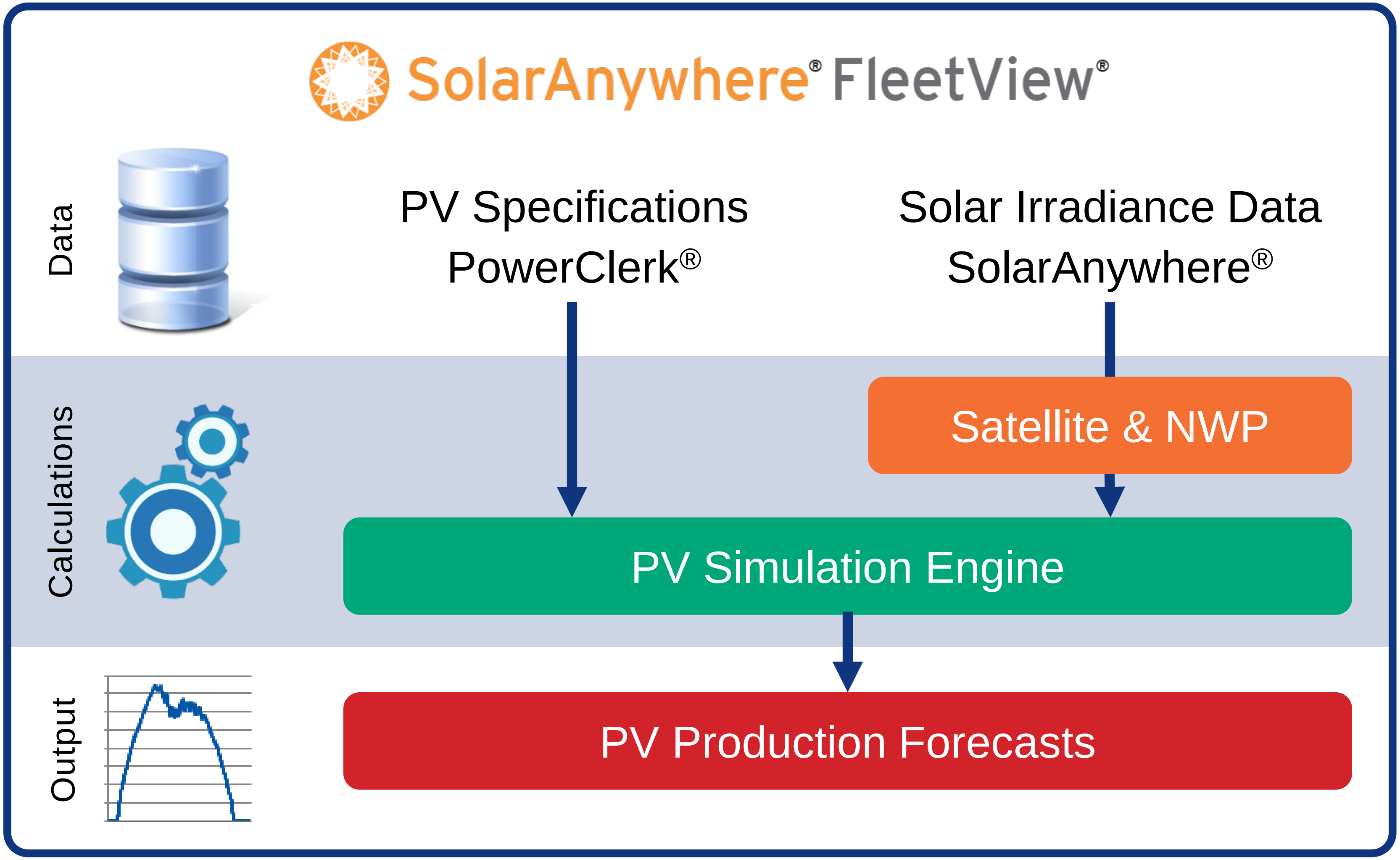
Data courtesy of the CAISO

FleetView® PV Simulation Methodology



SolarAnywhere® FleetView®

Data

PV Specifications
PowerClerk®

Solar Irradiance Data
SolarAnywhere®

Calculations

Satellite & NWP

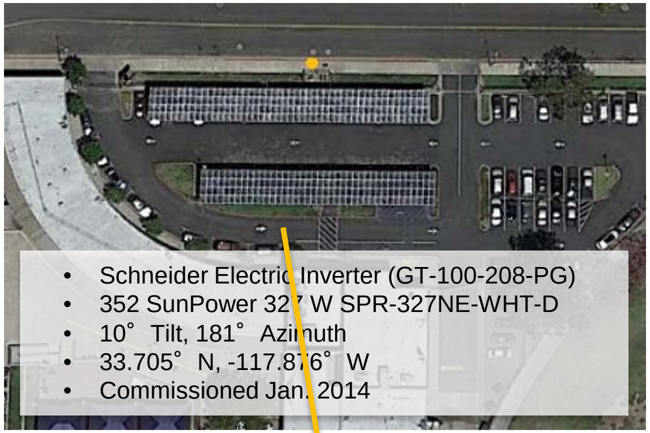
PV Simulation Engine

Output

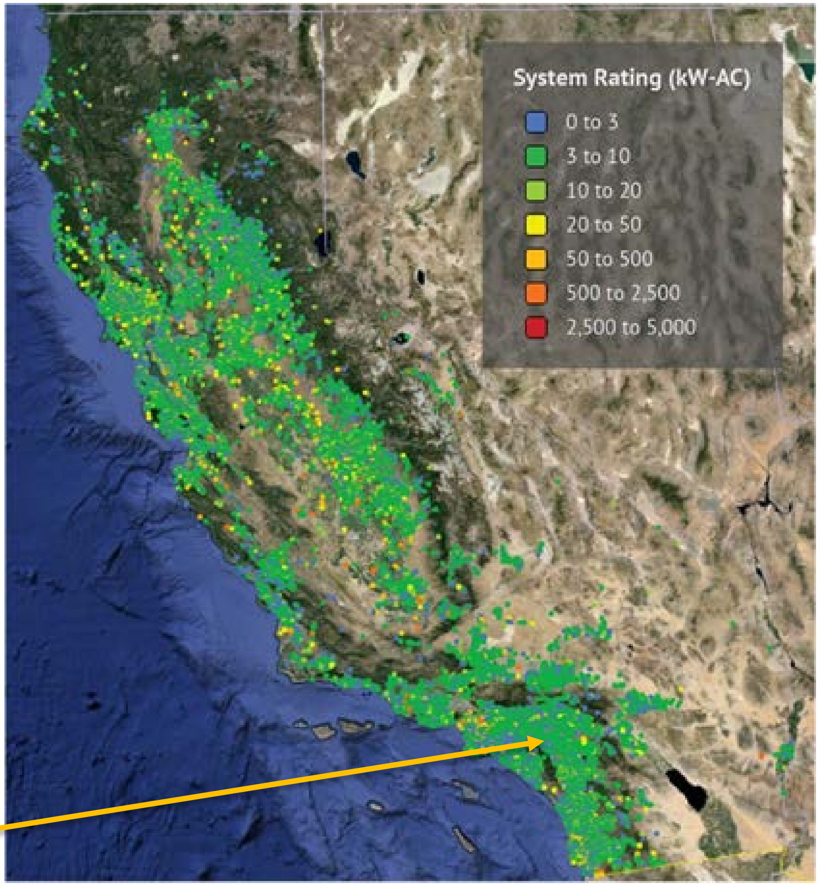
PV Production Forecasts

Captures Behind-the Meter (BTM) Fleet Locations and Diversity

- PowerClerk® links administration to fleet simulation
- Use same methodology as employed with utility-scale PV simulations

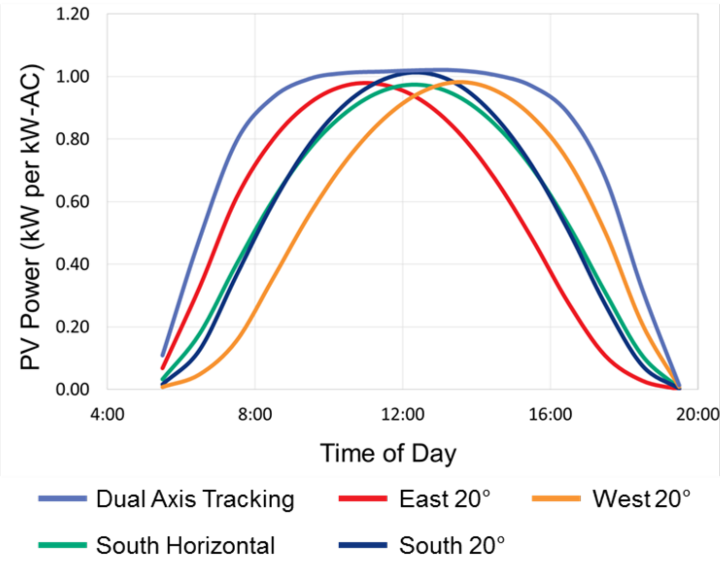


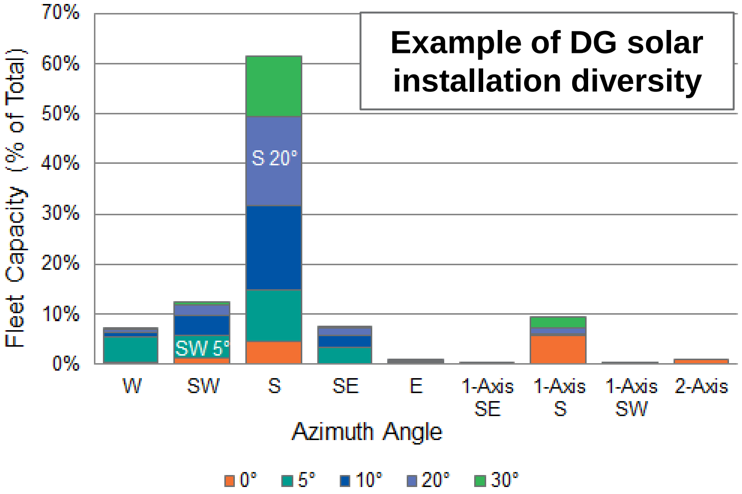
- Schneider Electric Inverter (GT-100-208-PG)
- 352 SunPower 327 W SPR-327NE-WHT-D
- 10˚ Tilt, 181˚ Azimuth
- 33.705˚ N, -117.876˚ W
- Commissioned Jan. 2014



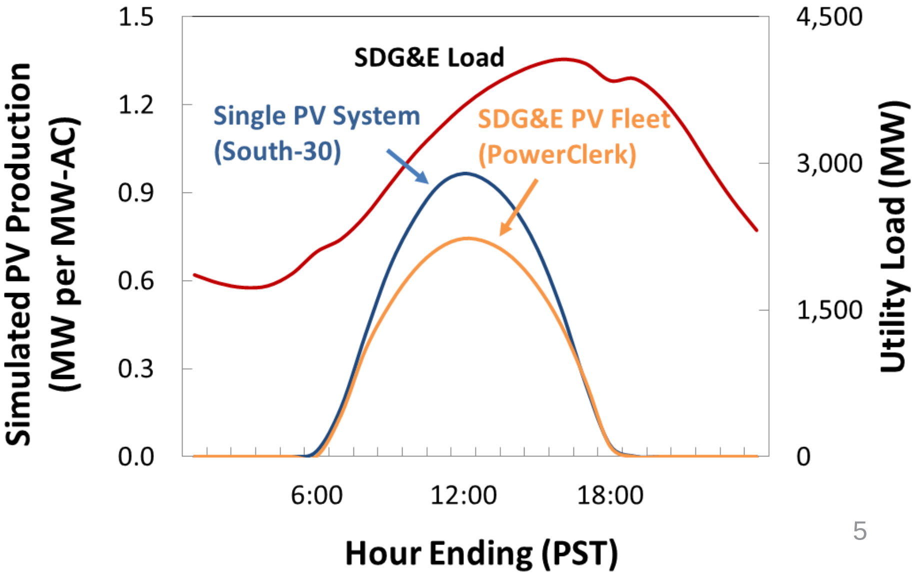
Regional and system-wide BTM simulation capabilities

Advantages of Explicit PV Fleet Simulations





- Significant variance in PV energy production by orientation
- Wide distribution of PV systems can alter fleet PV energy output



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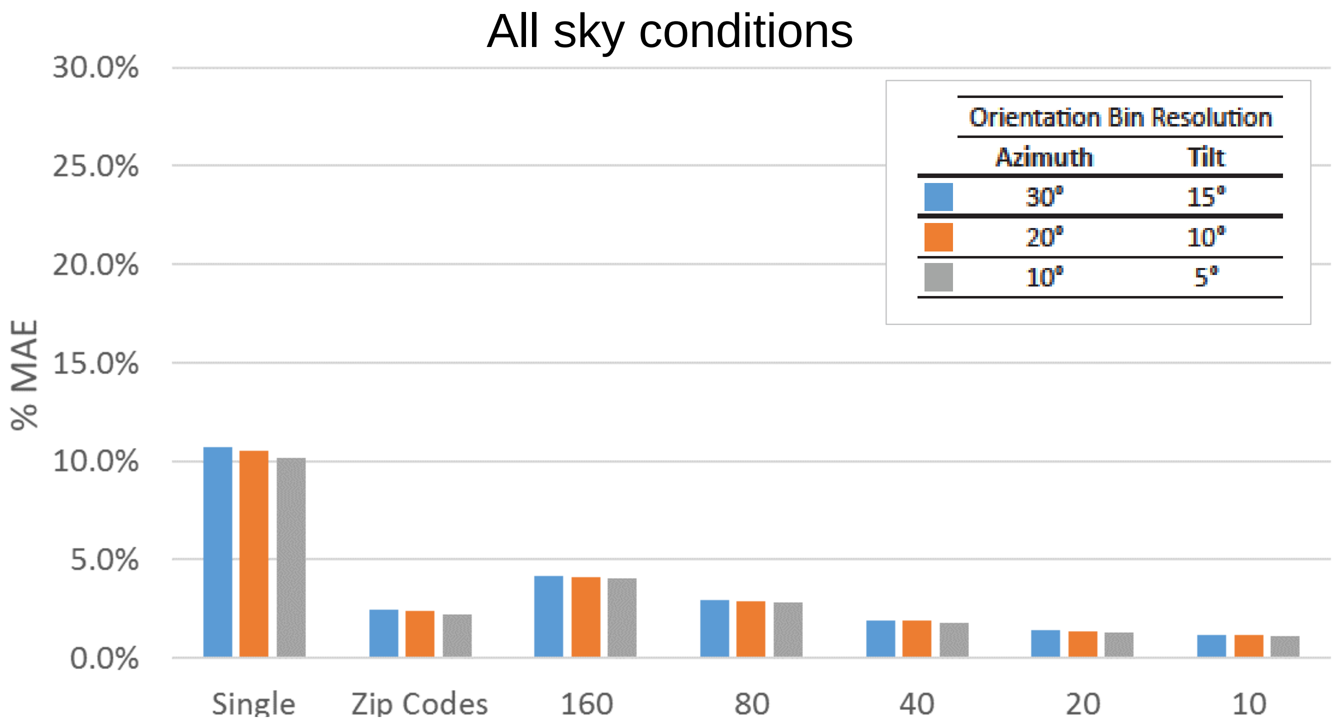
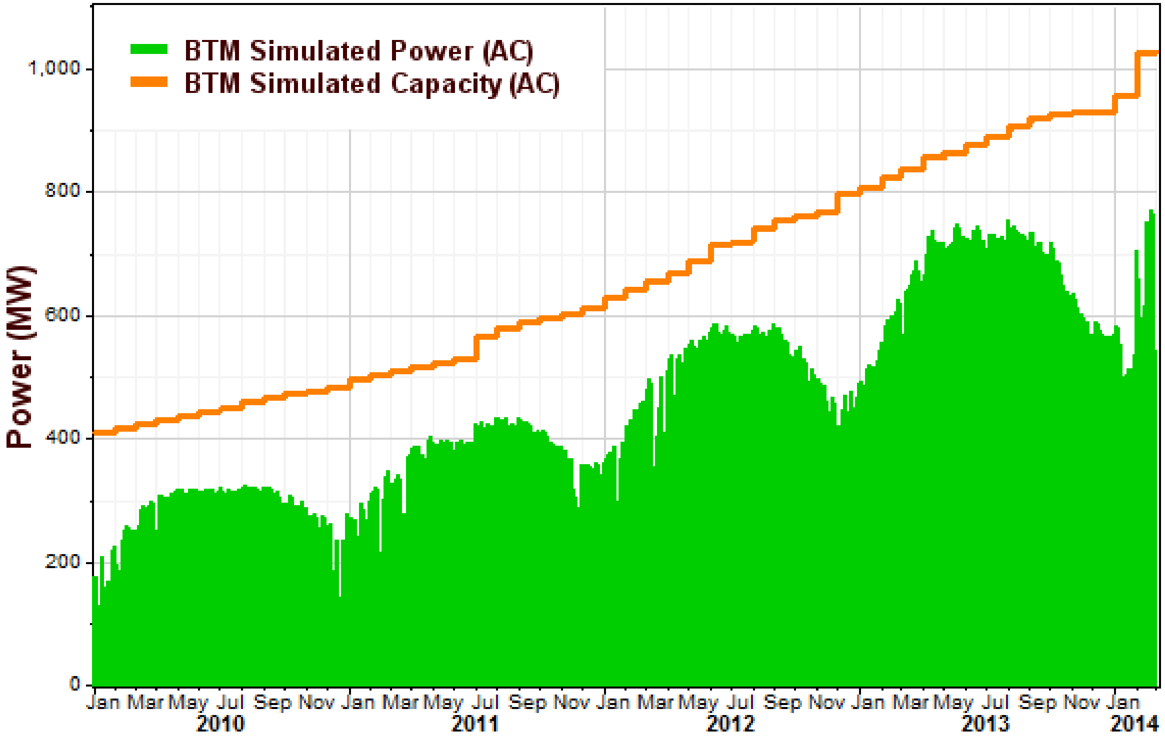
Accuracy Compared to Baseline Fleet

Assumed fleet shapes introduce avoidable error

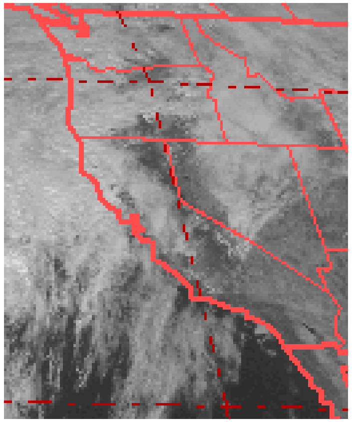


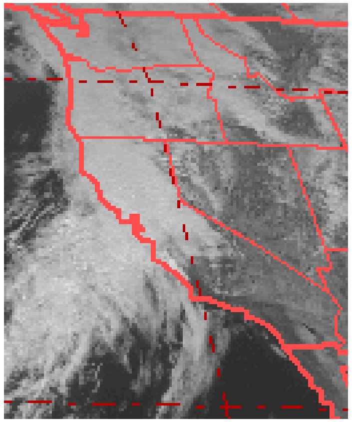
Validation in Load Forecasting Models

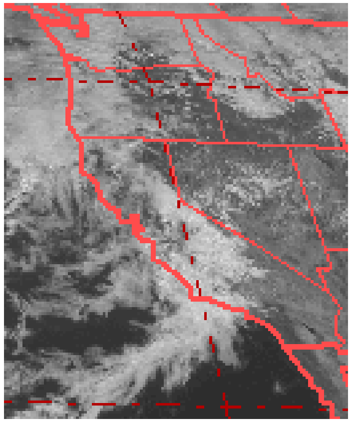
- Itron and CAISO evaluated CPR’s BTM PV fleet historical production as training input into CAISO’s ALFS
- PG&E sub-region was modeled from Jan 2010 through Feb 2014

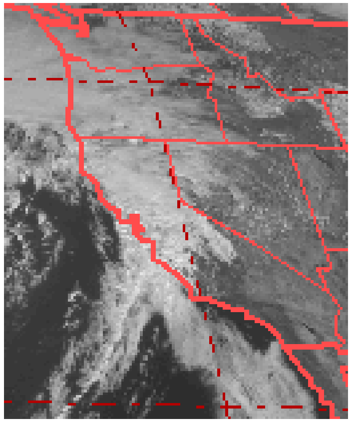


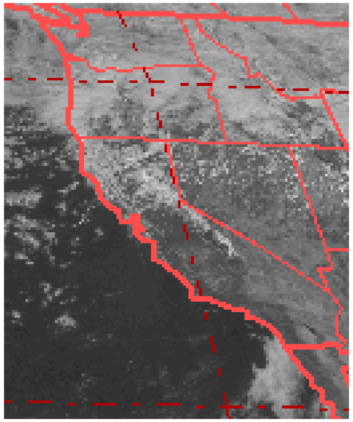
ALFS Forecasting Results for Sample Days

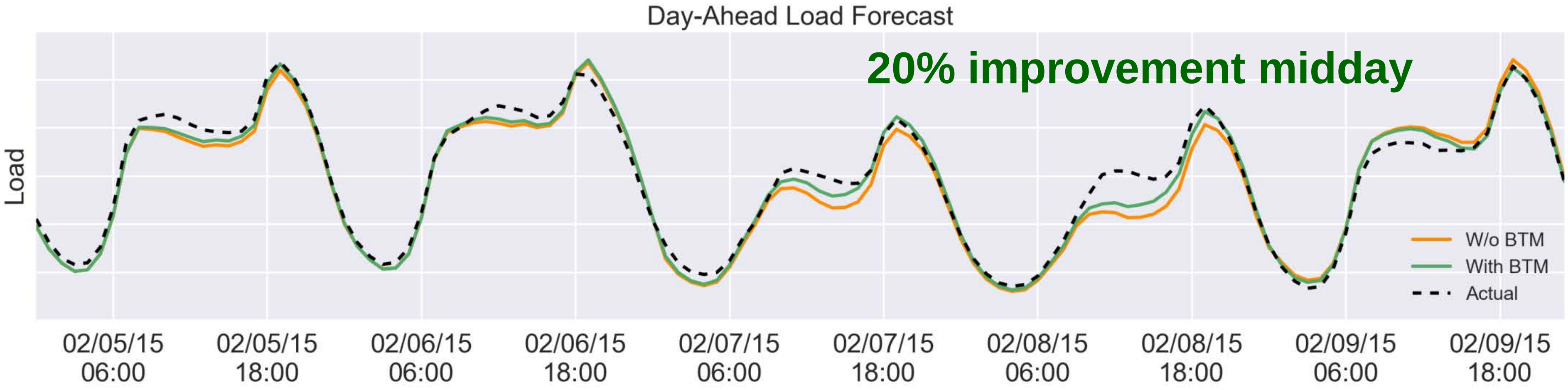

2/5 12 LST


2/6 12 LST


2/7 12 LST


2/8 12 LST

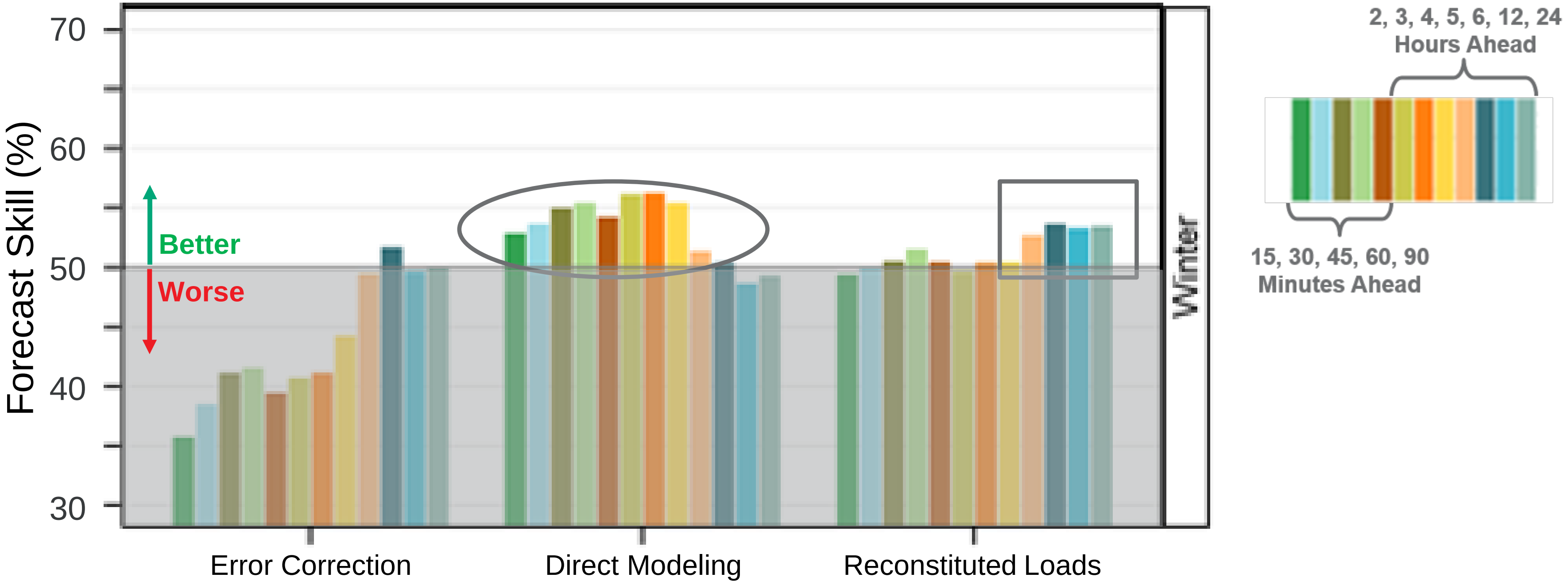

2/9 12 LST



20% improvement midday

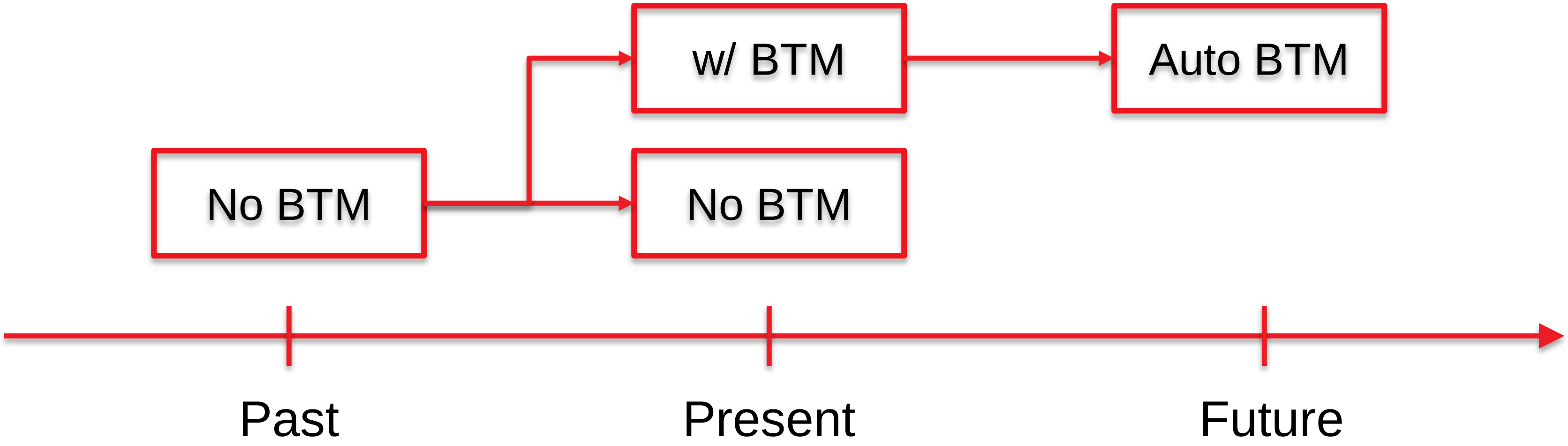
ALFS Forecast Skill for all CAISO Zones

Correctly applying BTM input can lead to ALFS improvement at all times



Current Status of CAISO BTM Forecasts

- Parallel ALFS forecast with BTM inputs used to situationally adjust operational ALFS
- Working with Itron to automate BTM forecast use



Applications

- Integrate PV modeling into utility planning and operation tools (EPIC, CPR teamed with Itron)
- Demonstrate distribution grid operation with PV and storage (DOE SHINES, CPR teamed with EPRI)
- Forecast individual commercial buildings and shift HVAC loads to smooth PV impact
  (DOE Incubator, CPR teamed with EdgePower)

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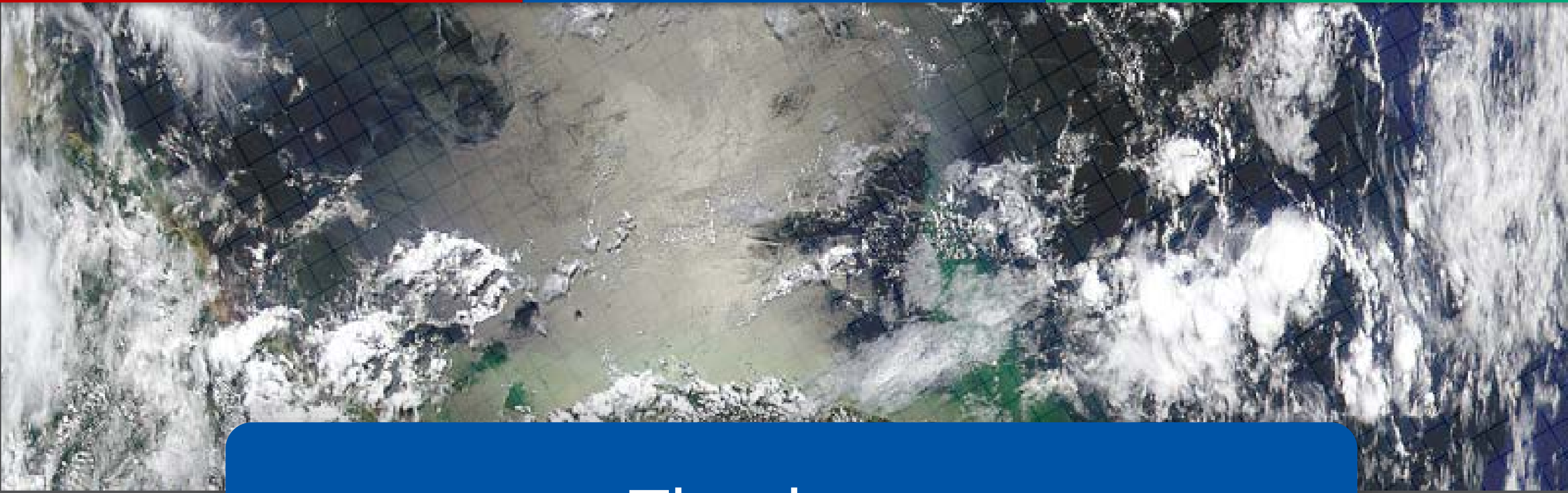
CALIFORNIA ENERGY COMMISSION



Thank you

Please feel free to contact us for any details or clarification related to presentation

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Clean Power Research®

Observability and Control Distributed Energy Resources

Jim Reilly, Consultant

FOURTH DISTRIBUTED ENERGY RESOURCES WORKSHOP

ATLANTA, GA

August 3, 2016

RECOGNITION

Thanks to:

Department of Energy, Office of Electricity Delivery and Energy Reliability

Dan Ton

Energy Systems Division, Argonne National Laboratory

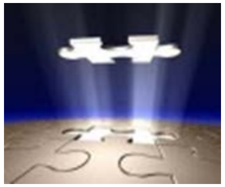
Jianhui Wang
Ning Kang
Ravindra Singh

Grid Integration Group, Lawrence Berkeley National Laboratory

Emma Stewart

For material used in this presentation.

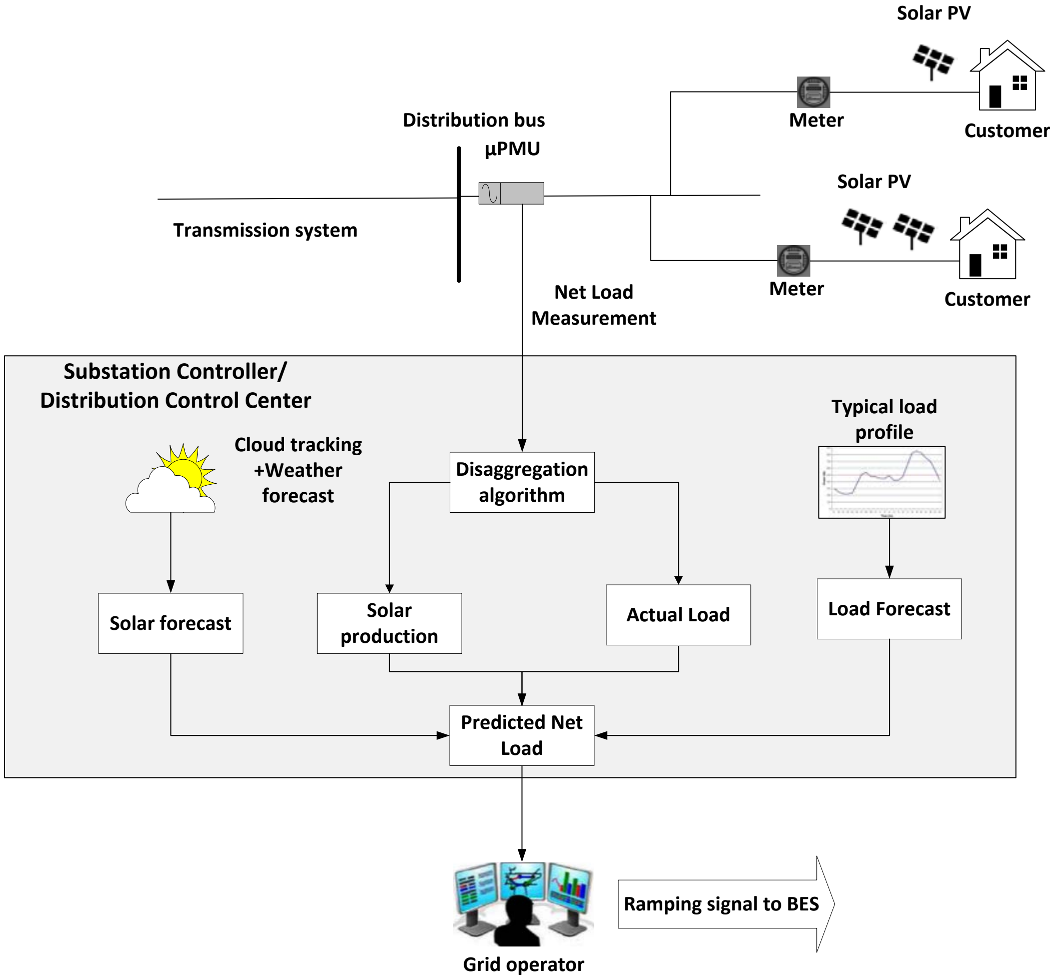
Themes



- Issues and Solution to Behind-the-Meter DER
- Technologies to grid observability with high DER penetration
  - DER forecasting Using Smart Sensor Network and Data Fusion
  - Online PV Disaggregation
- Control Architecture of DERs
- DMS Integration

Issues & Solution to Behind-the-Meter DER

- Behind-the-meter DER definition
  - A DER generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy.
- Issues with behind-the-meter DERs
  - At a substation: net load = load – DER
  - Potential sudden changes in the substation net load due to variability and intermittency of DERs will cause great challenges to the bulk power system ramping needs
- Solutions to behind-the-meter DERs
  - Applying online DER disaggregation and forecasting techniques for the behind-the-meter DER output and customer behavior to offer enhanced predictability on the changes in net loads at a particular substation



Solar PV

Customer

Meter

Distribution bus

µPMU

Transmission system

Solar PV

Meter

Customer

Net Load Measurement

Substation Controller/ Distribution Control Center

Cloud tracking +Weather forecast

Disaggregation algorithm

Typical load profile

Solar forecast

Solar production

Actual Load

Load Forecast

Predicted Net Load

Ramping signal to BES

Grid operator

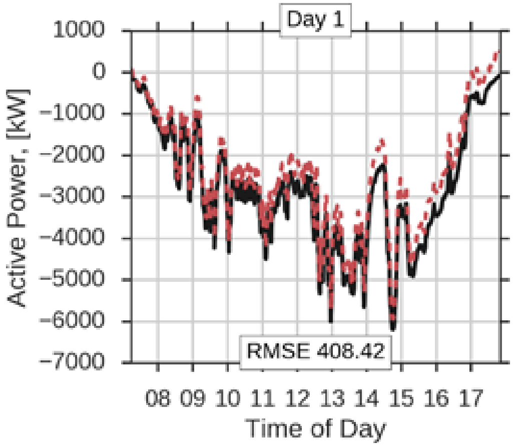
Courtesy: ANL

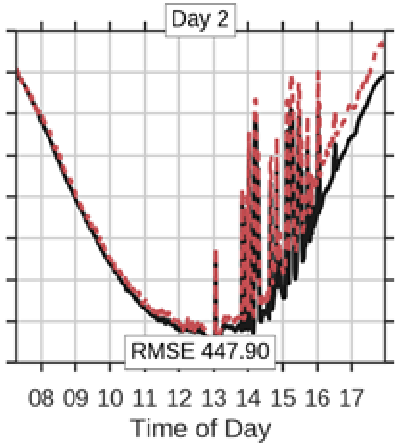
DER Forecasting Using Smart Sensor Network and Data Fusion

- Motivation
  - Accurate forecasting of renewable production improves grid observability and reliability
  - Uncertainty in prediction from individual tracking devices can be reduced by real-time data communication and data fusion
- A data fusion based method to improve the quality of solar forecasting using distributed sensing
  - Develop a cloud tracking model
  - Each tracker estimates the cloud size, position, speed and opacity, and communicates its estimates to neighbors
  - Centralized and distributed data fusion schemes can be developed
- Main challenges
  - Variability in altitude and opacity of the cloud
  - Sun orientation because of earth’s rotation and weather changes
  - Accurate sensor model for cloud trackers
  - Determination of the height of the cloud

Online PV Disaggregation

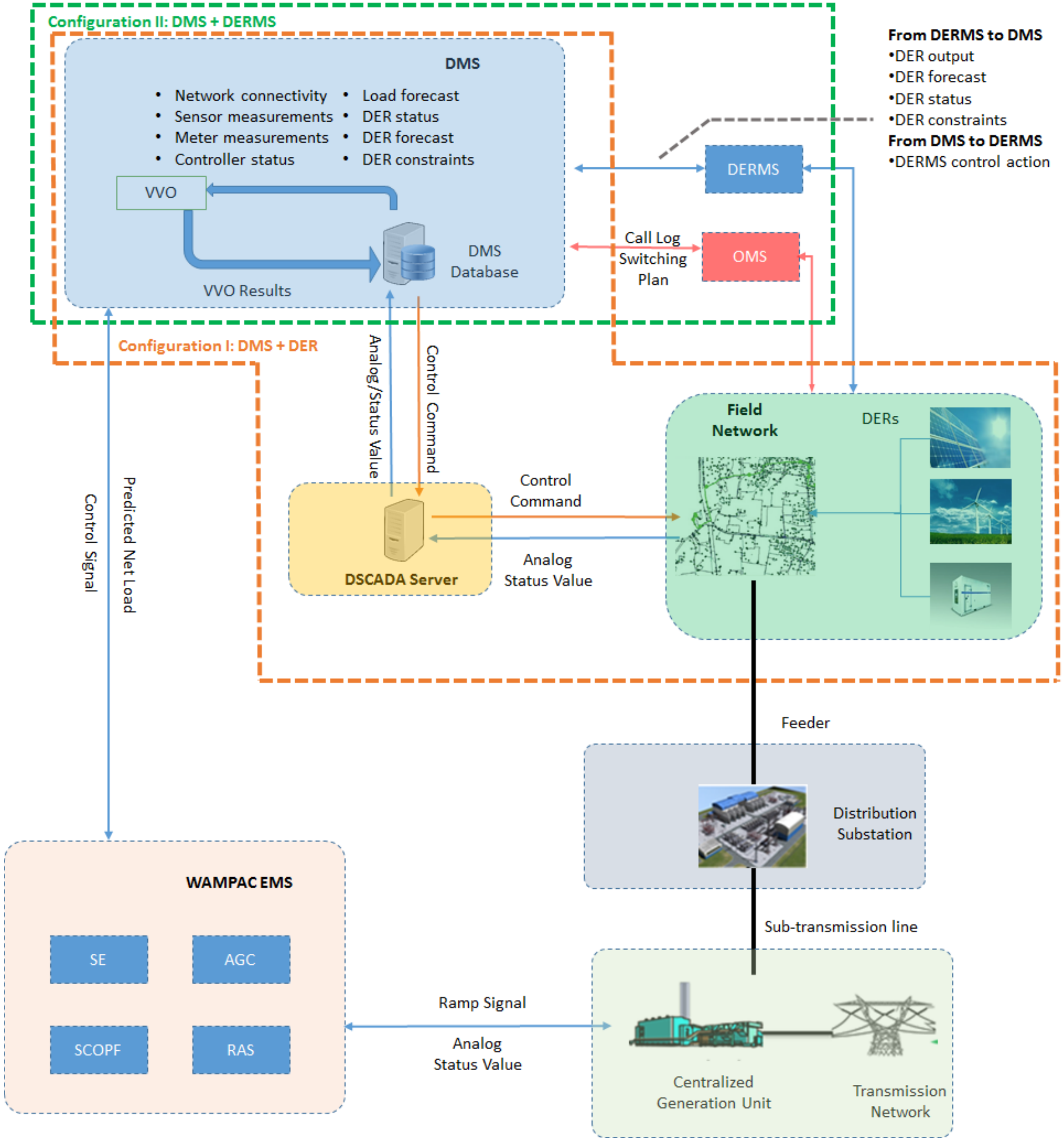
- Definition
  - From the substation point of view, identify the total load and total DER generation individually from the net load in real time
- Motivation
  - Model-based approaches estimate PV generation as a function of generation capacity and irradiance measurements – but suffers inaccuracy
  - Individual communication from behind the meter inverters would be a solution – but reliant on customer communication networks
  - Disaggregation of PV and Load gives visibility, on both the short term performance, and correlation of feeder conditions such as voltage profile
- New data-driven approaches using µPMU networks
  - Estimate real time (behind the meter) PV production downstream of µPMU measurement device (located at substation)
  - Using real-time measured reactive power at substation and irradiance proxy to realize online PV disaggregation
  - Result in a 6% RMSE of installed capacity over all sky conditions
  - Improvement over existing state of the art ~15%



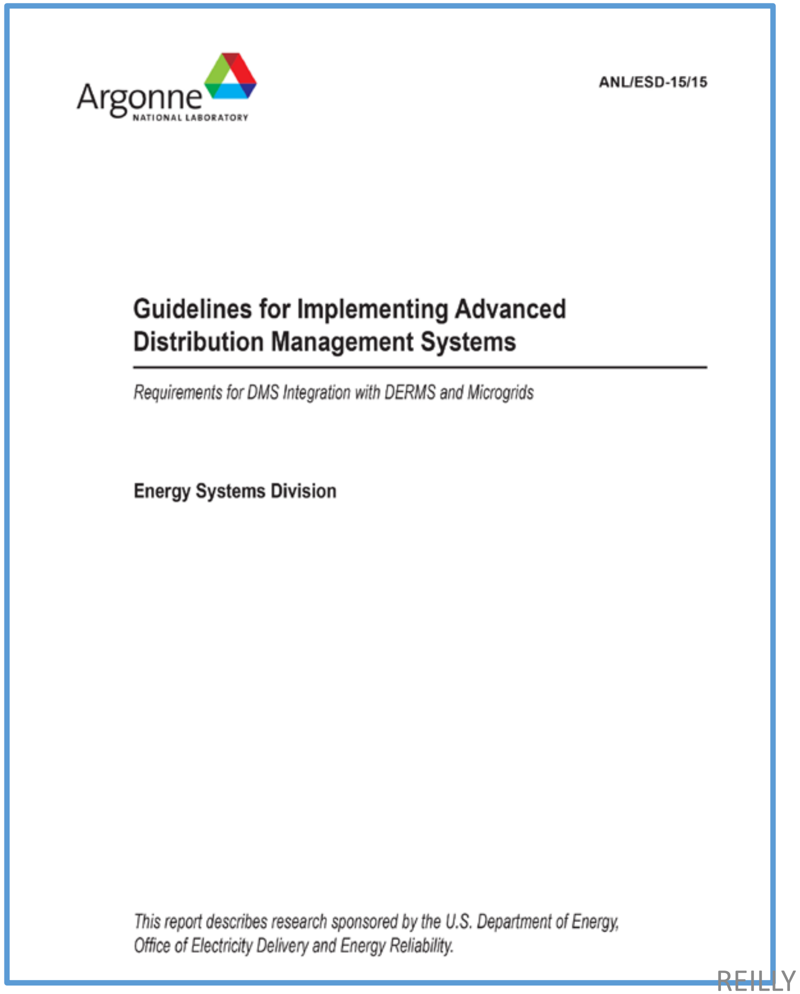


Control Architecture of DERs

- Control of DERs are envisioned in ADMS projects
- VVO is one example that controls DERs
- Various control architecture of DERs
  - Configuration I: DMS + individual DERs
  - Configuration II: DMS + DERMS
- Interface with Bulk Electric System
  - DMS sends predicted net load to EMS
  - EMS sends control signal to DMS
  - EMS sends ramp signal to BES



DMS Integration
DERMS and Microgrid Controller



Argonne NATIONAL LABORATORY

ANL/ESD-15/15

Guidelines for Implementing Advanced Distribution Management Systems

Requirements for DMS Integration with DERMS and Microgrids

Energy Systems Division

This report describes research sponsored by the U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability.

Responsibilities of microgrid for DMS

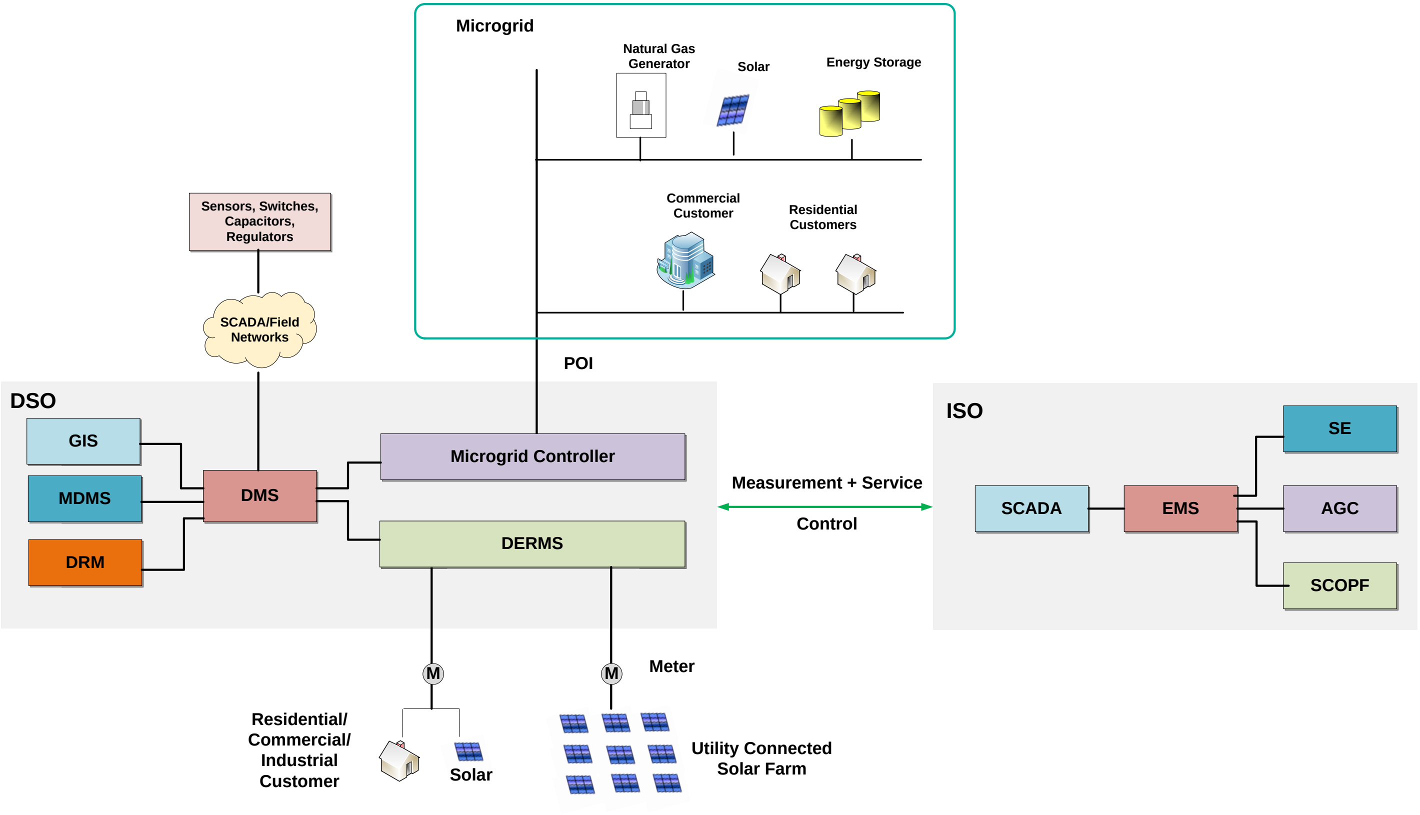
- Microgrid controllers are responsible for maintaining real power exchange, healthy voltage profiles at the active POCs when connected to the distribution grid
- Microgrids should automatically disconnect from the distribution grid in any grid fault condition beyond the threshold of ride-through

Responsibilities of DMS for microgrid

- DMS should provide operation guidance, including the voltage ranges and power exchange fluctuation tolerance around the scheduled targets at active POCs to the microgrids
- DMS can initiate emergency requests to microgrids for clearly defined specific emergency support, including support through wheeling

Relationship Between Local Controllers and DERMS with ISO EMS

- Local controllers / DERMS communicate with the utility DMS system at the DSO level.
- At the ISO level the DMS communicates with the EMS. In this way the TSO can have observability and control over DER across jurisdictions.



Courtesy: ANL

Reilly Associates
Red Bank, NJ 07701
Telephone: (732) 706 9460
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Distributed Energy Resources Workshop: Observability and Control

Jessica Harrison, Director of R&D, Market Services

August 3, 2016

Geographically, MISO is the largest regional transmission organization and independent system operator in North America

Midcontinent ISO	
High Voltage Transmission	66,000 Miles
Installed Generation	180,000 MW
Installed Generation	1,600 Units
Peak System Demand	127,000 MW

MISO Vision

The most reliable, value-creating RTO

Mission

Work collaboratively and transparently with our stakeholders to enable reliable delivery of low-cost energy through efficient, innovative operations and planning.

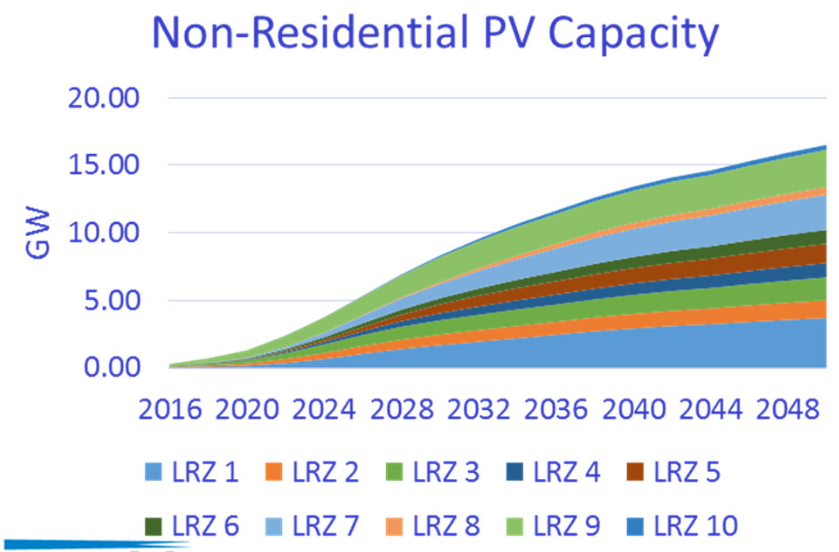
Solar generation in MISO is slow but has potential

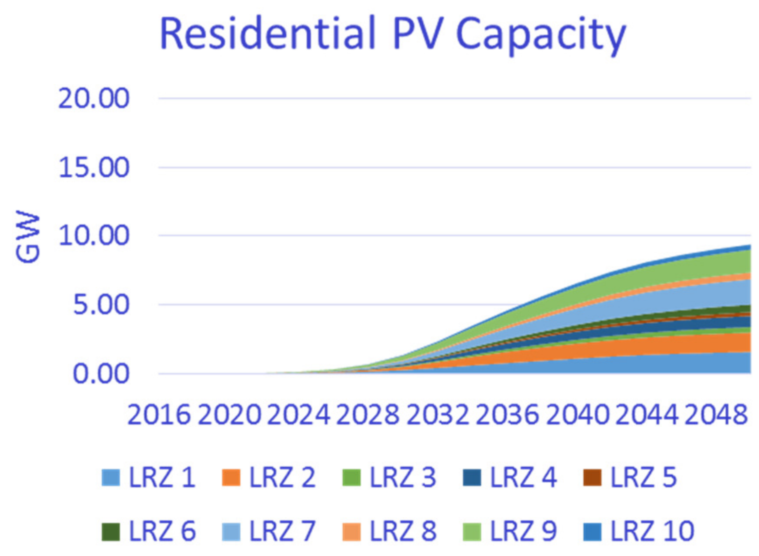
Today

- Grid-connected
  - ~ 200 MW solar (registered) in service date of Dec 2016
  - Estimated 6,000 MW under interconnection study
- Behind-the-meter
  - Estimated 200 MW (about 0.2% of MISO total load) installed

Future

- Behind-the-meter technical potential estimates





Source: MISO & Applied Energy Group

DER Integration is a MISO R&D focus area

Research Questions

- Should and how might we adapt *existing* tools that address load and generation variability / forecast errors to better integrate DERs?
  - Ramp product (implemented on May 1, 2016)
  - Fast AGC
  - Demand Response Resource, Load Modifying Resource, Energy Storage
  - Load forecasting & monitoring
- What *additional* solutions (interconnection requirements or market products) are or aren't needed?
  - Primary frequency response
  - Volt/Var implications?
  - Market pricing dynamics & estimating responses

DER Integration is a MISO R&D focus area

Research Questions (cont'd)

- What metering / telemetry might be required or would be helpful?
  - Situational awareness or forecasting support (day ahead to real time)
  - Appropriate regional samples, data collection processes?
  - Appropriate requirements (security, time delays, accuracy)?
  - Accuracy required?
- What additional system needs will there be?
  - What volume of data / constraints might our system need to handle and how might we best manage that?
  - Cybersecurity implications under different integration models?
  - What levels should we model to? (Depends in part on answers to above questions)
- Measurement and verification – baseline and response assessments
  - Demand response vs. generation approaches?

Additional Aspects to Consider

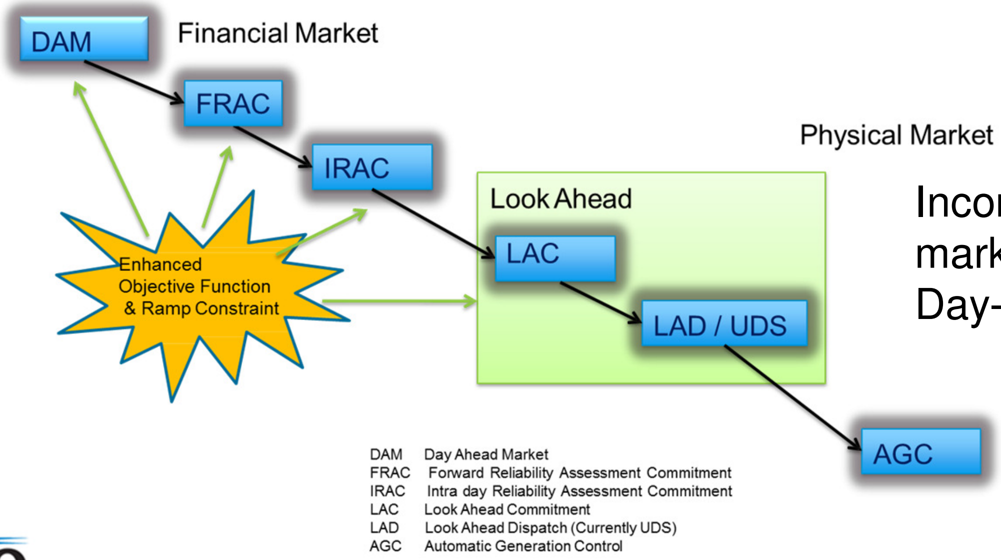
- How might distribution-level technologies / capabilities ultimately shape the profiles viewed in the aggregate at the bulk scale and how might that change over time?
  - Distribution-level capabilities relative to DER deployment timelines
  - Controllability versus observability

- What kinds of capabilities, requirements or roles, if any, can we define independent of:
  - DER penetration (total penetration and mix of DERs)
  - State policies
  - Supporting resource portfolio makeup

Example: Ramp Product

Ramp Capability Product addresses the increasing system ramping needs arising from recent market evolutions

- Develop a market-based approach for ramp management that leverages existing operational experiences
- Systematically pre-position resources with ramp capability to manage net load variations and uncertainties
- Provide transparent price signals to incent resource flexibility and economic investment



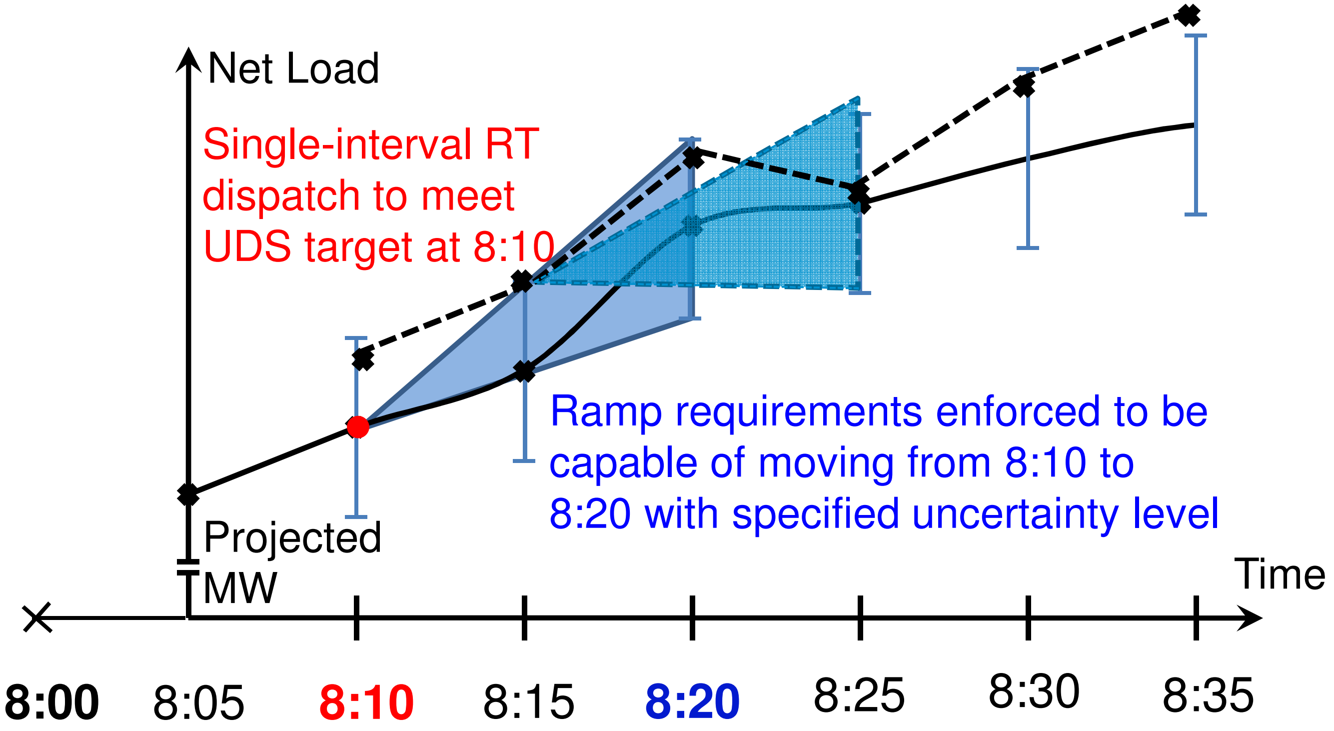
DAM	Day Ahead Market
FRAC	Forward Reliability Assessment Commitment
IRAC	Intra day Reliability Assessment Commitment
LAC	Look Ahead Commitment
LAD	Look Ahead Dispatch (Currently UDS)
AGC	Automatic Generation Control

Incorporated in each stage of the market (prior to AGC), including both Day-Ahead and Real-Time markets

Example: Ramp Product

Ramp requirements are set to manage net load variations and uncertainties ten minutes beyond dispatch target

- Bi-directional: Up and down ramp requirements are enforced independently with separate quantities
- System-wide: Deliverability captured through ramp procurement post-deployment transmission constraints



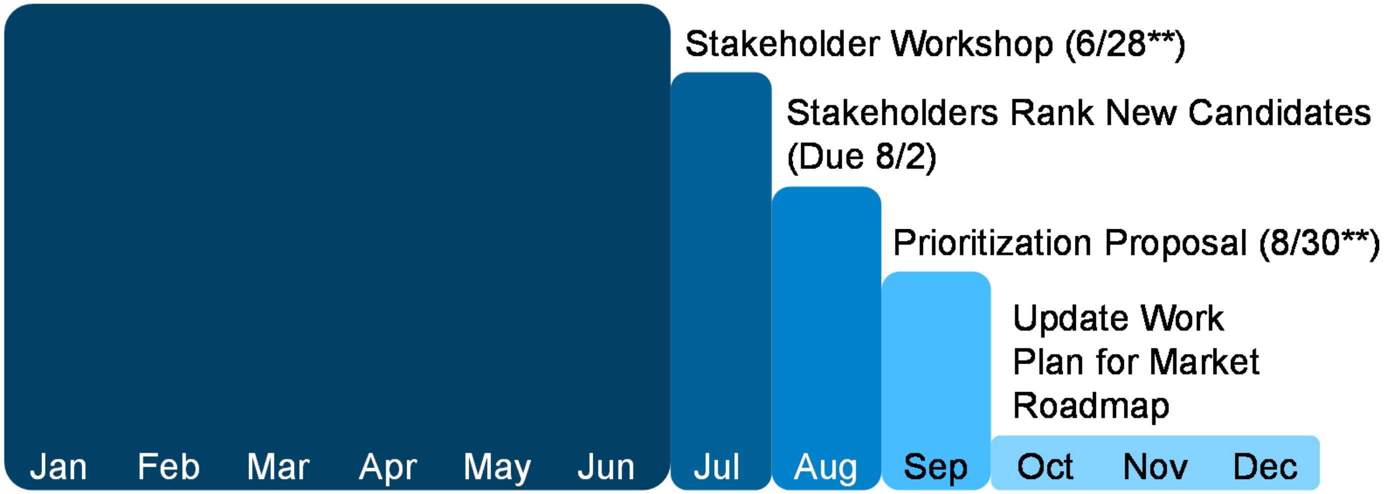
Single-interval RT dispatch to meet UDS target at 8:10

Ramp requirements enforced to be capable of moving from 8:10 to 8:20 with specified uncertainty level

MISO Market Roadmap Candidates

- Energy Storage, including behind the meter energy storage
- Flexibility: e.g., Automatic Generation Control (AGC) enhancement for fast-ramping resources
- Demand Response deployment

2016 Timeline



Submit Issue & Market Roadmap Candidate Addendum (Final deadline 5/18*)
New Candidate Fact Sheets Published (Ongoing through 6/28)

Stakeholder Workshop (6/28**)

Stakeholders Rank New Candidates (Due 8/2)

Prioritization Proposal (8/30**)

Update Work Plan for Market Roadmap

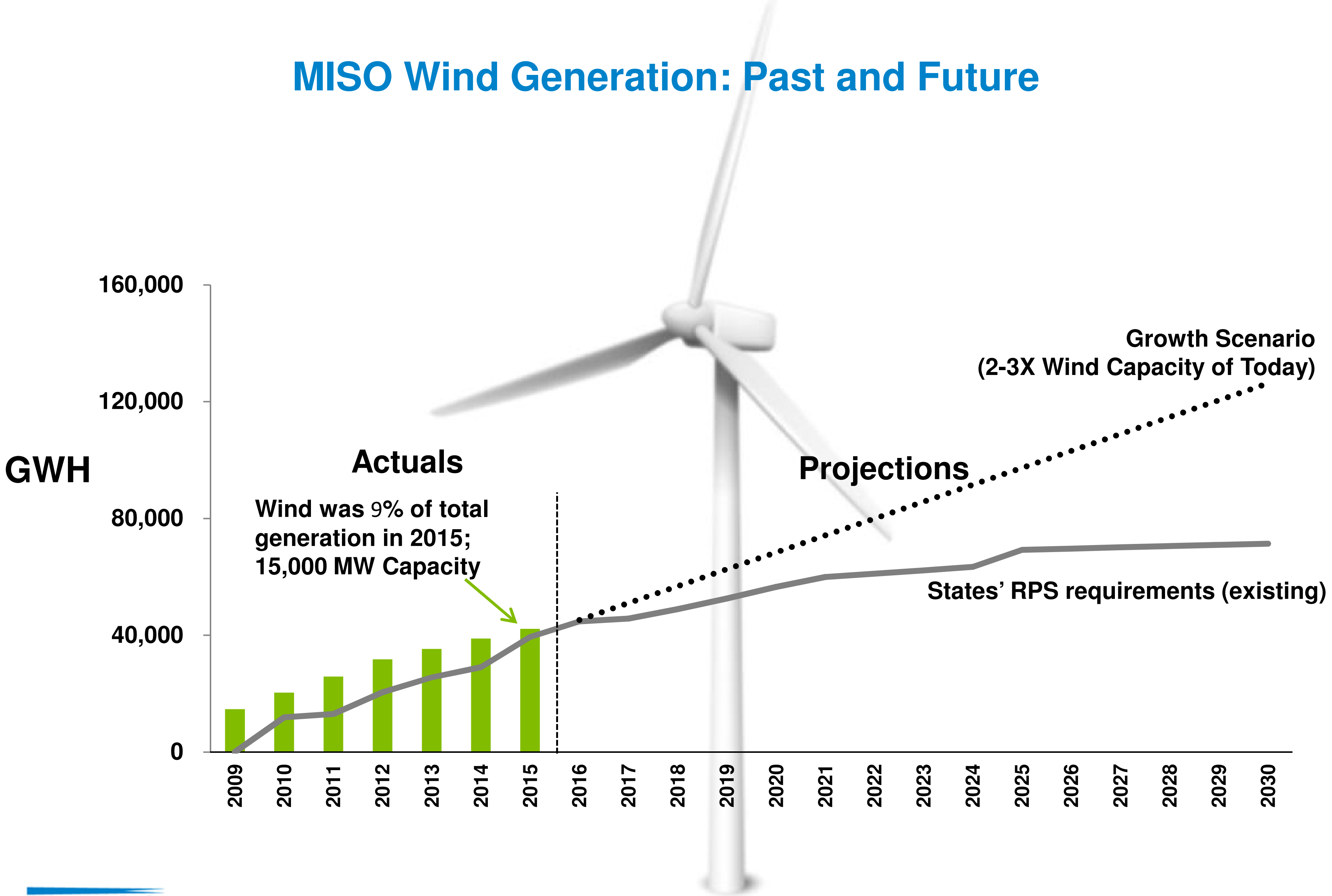
Publish Monthly Updates to Market Roadmap, Project Fact Sheets and Metrics

*Candidates submitted after May 18, 2016 will be considered for prioritization in the 2017 Market Roadmap Process
**Workshop and prioritization proposal dates aligned with MSC meeting dates

Appendix

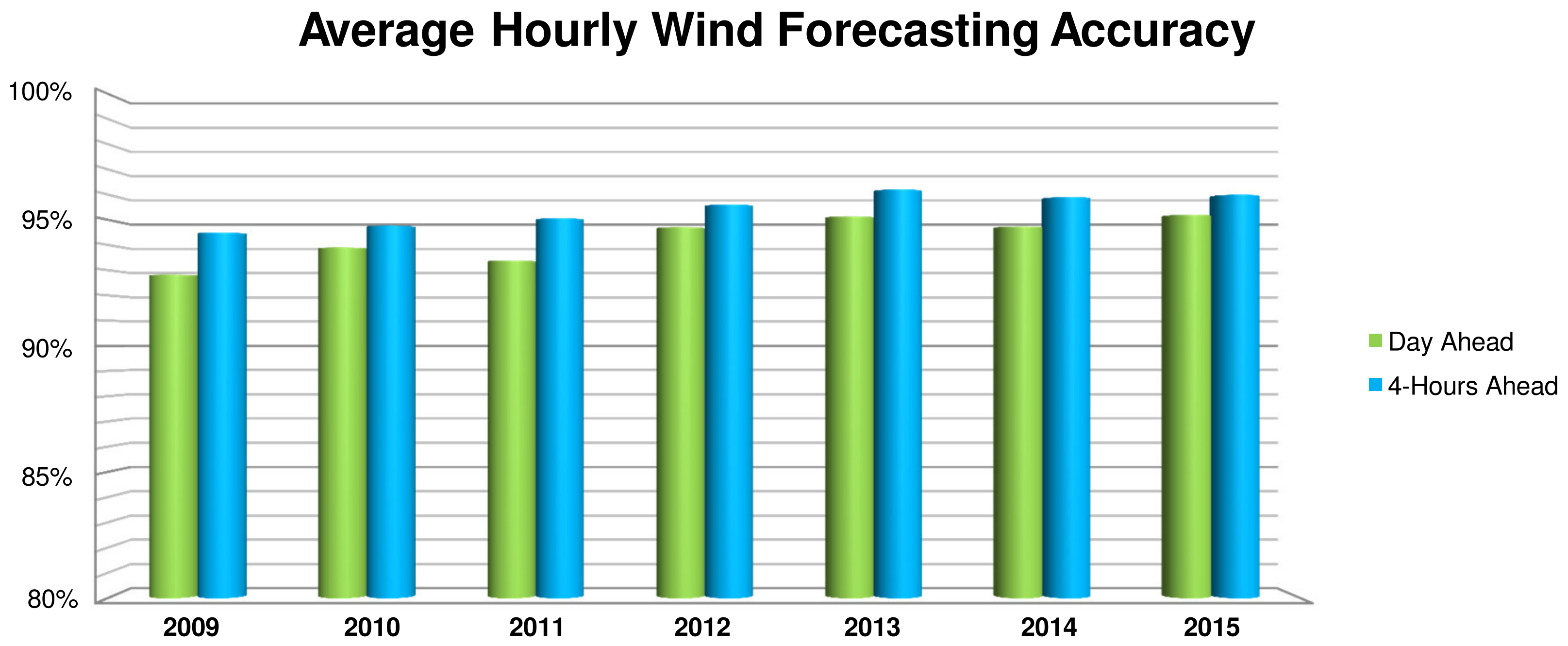
MISO expects significant growth in wind generation

MISO Wind Generation: Past and Future



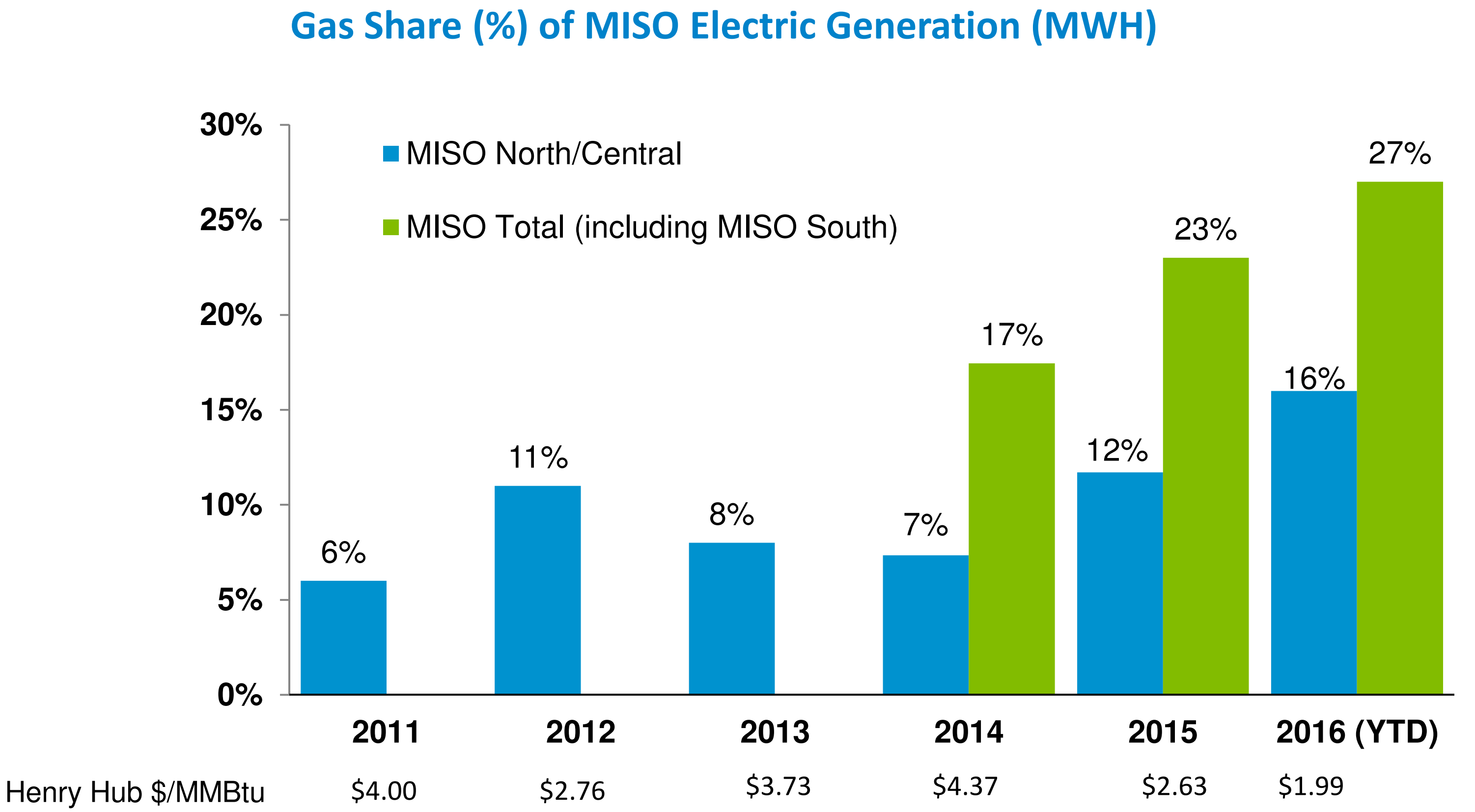
MISO’s wind forecast has improved since 2009

MISO’s Day-Ahead wind forecast accuracy
has improved by 2.5% since 2009



- Wind forecasting accuracy is calculated using an industry-wide standard and is expressed as a percent of installed wind nameplate capacity.
- Based on data available for MISO to compare with other RTOs, MISO’s performance is best-in- class.
- Reduction in 2014 day-ahead performance is the result of changing the reference point for day-ahead data capture from 8:00pm EST to 4:00pm EST
- Reduction in 2014 four-hour ahead performance is a result of weather prediction errors, icing conditions, and commercial operational date schedule changes.

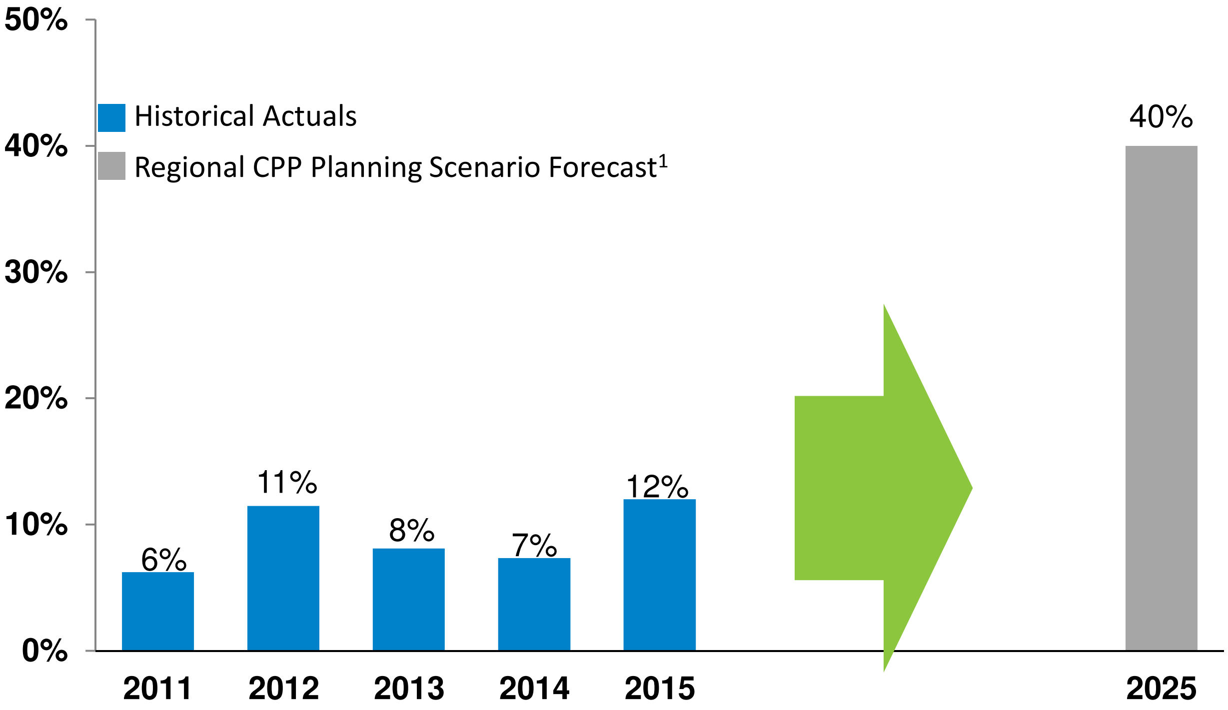
MISO has experienced significant growth in gas



- 2015 significantly eclipsed prior gas utilization…and the trend continues in 2016 (YTD)
  - Though MISO South historically has high gas reliance, gas increased appreciably from 46% in 2014 to 55% in 2015 and 58% in 2016 (YTD)

With more natural gas growth is expected

Gas Share (%) of Electric Generation (MISO North/Central)



2025 indicative gas burn	4.5 – 5.0 Bcf/day

Shift driven by increased gas-fired capacity and increased capacity factors

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1 - Forecast figure based on MISO MTEP16 assumptions and models for "Regional Clean Power Plan" scenario (assumes 26 GW coal retirement, 14 GW new gas-fired combined cycle, carbon cost $32/ton in 2025, solar and wind include an economic maturity curve to reflect declining costs over time). The gas price forecast applicable to year 2025 has been updated to reflect recent outlooks with Henry Hub gas prices assumed at ~$4.45/MMBtu.

California ISO

Distributed Energy Resources Workshop

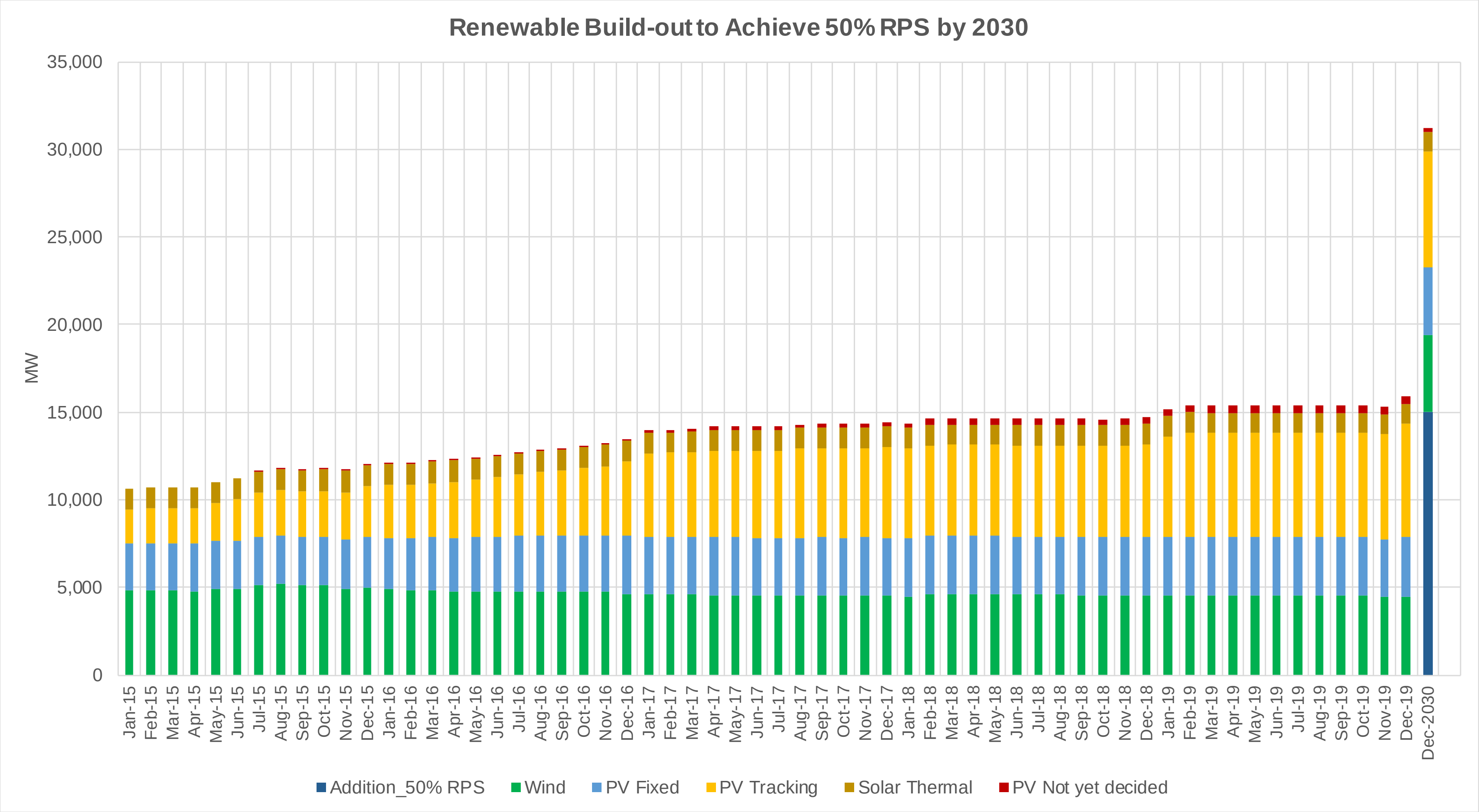
Panel 4 – Observability and Control

Potential Reliability Impacts of High Levels of Distributed Energy Resources

Clyde Loutan, Sr Advisor - Renewable Energy Integration, Market Analysis and Development

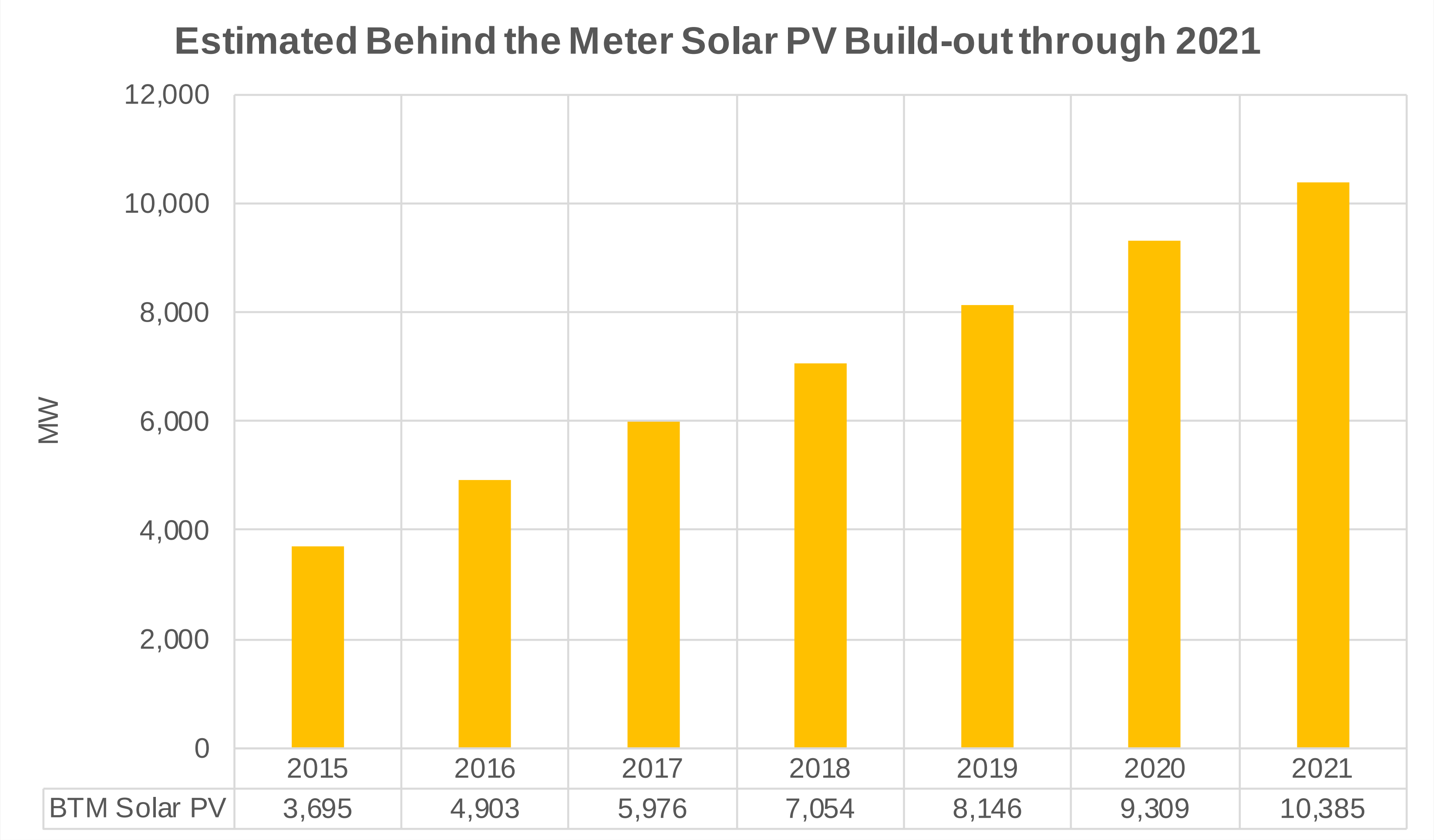
August 3, 2016

Expected build-out of wind and solar resources through 2019 and additional renewables to achieve 50% RPS by 2030



California ISO

Expected behind the meter solar PV build-out through 2021



Estimated Behind the Meter Solar PV Build-out through 2021

	2015	2016	2017	2018	2019	2020	2021
BTM Solar PV	3,695	4,903	5,976	7,054	8,146	9,309	10,385

NERC has identified the following factors on bulk system reliability associated with DERs

- Need for establishing requirements to regulate the aggregated voltage at the point of interconnection to the transmission
- Potential over-generation during minimum load periods due to DER plus grid connected base load and non-dispatchable generation
- Need for developing standards for DERs wishing to participate in ancillary service markets
- Coordination and reconciliation of IEEE 1547 interconnection standards with proposed DER grid codes on fault current , low-voltage ride-through, frequency ride-through etc.
- Potential system protection coordination due to current flow reversal;
- Disconnecting DER during under-frequency load shedding can further reducing frequency
- System restoration coordination between transmission/distribution resources

How do we adapt to the high penetration levels of DER?

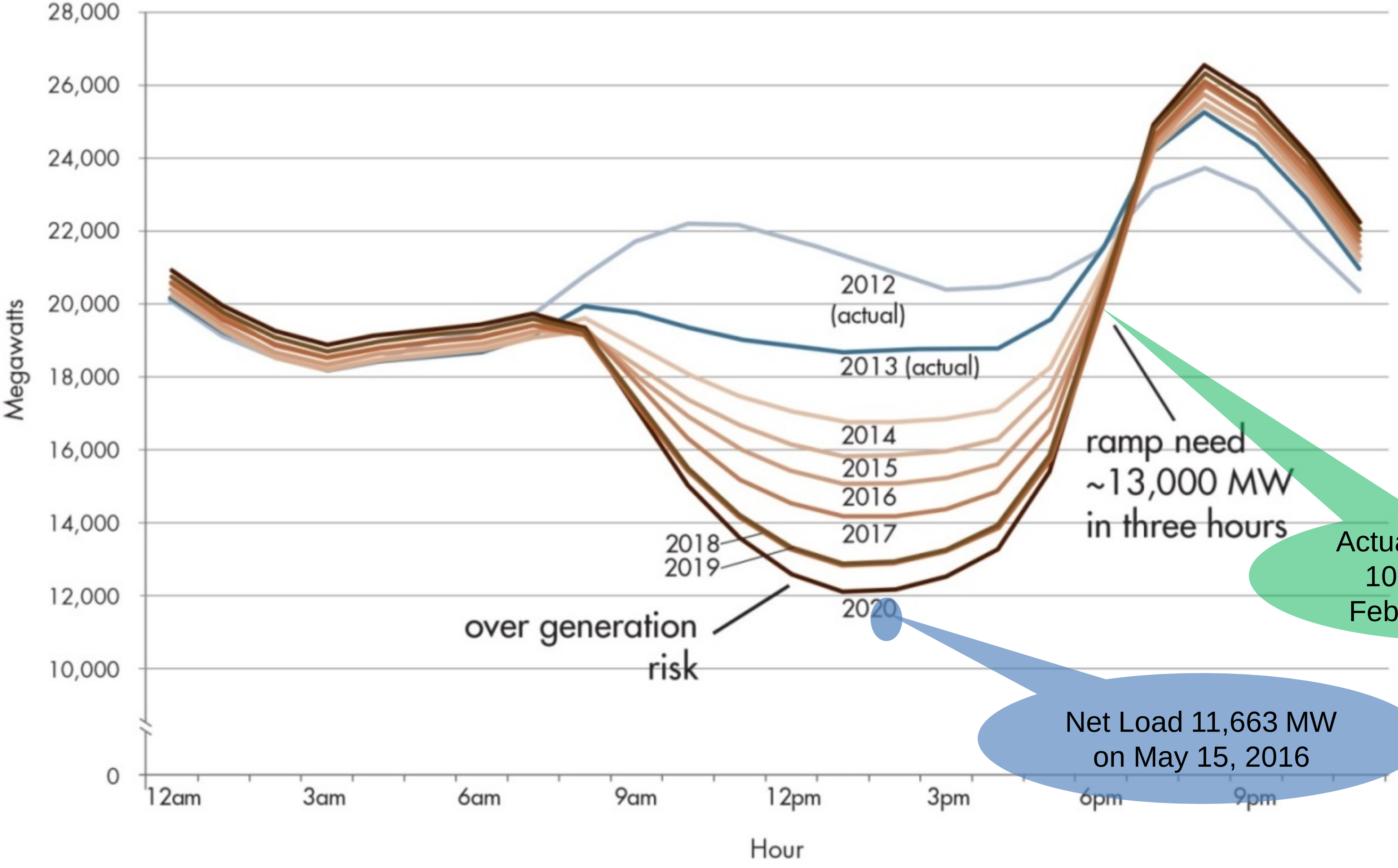
- Develop technical interconnect requirements as part of grid codes for DER
- Develop new planning and operating guidelines so system operator can better understand the impacts of DERs
- Identify areas where current reversal due to DER can result in thermal overloads on the grid
- Develop and incorporate day-ahead and real-time forecast for aggregated DERs production in applicable market applications
- Analyze areas with high levels of inverter-connected DERs to identify potential transient and small signal stability problems
- Coordinate transmission planning/operating studies with DERs, demand response resources, plug-in vehicles (PEVs), distributed storage etc.

Operational challenges on the grid associated with large scale DERs and loads

- Lack of visibility of distribution system
- Uncontrollable nature of DER output
- PV inverters in large amounts can affect the frequency response and voltage profile of the system
- Forecast assumptions of “net load” seen by operators
- Variability of “combined heat and power” production due to load, natural gas prices, real-time energy prices etc.
- Predicting price responsive loads behavior to real-time prices
- Demand response variability and forecast uncertainty
- Uncertainty/assumptions associated with commercial, Industrial and residential storage

Actual net-load lower than originally estimated due to increased amount of renewable resources including DER

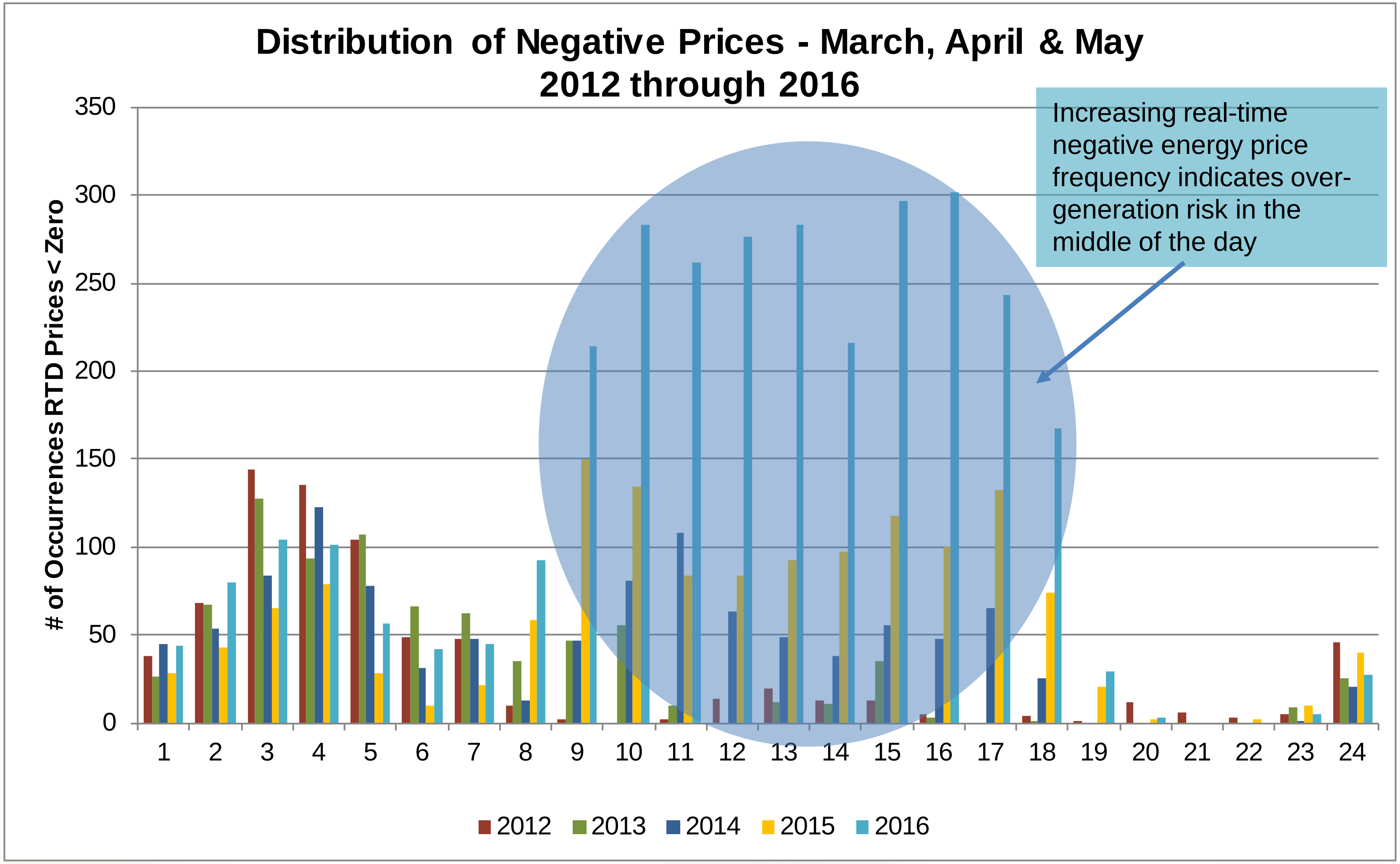
Typical Spring Day



Actual 3-hour ramp 10,892 MW on February 1, 2016

Net Load 11,663 MW on May 15, 2016

Negative energy prices indicating over-generation risk start to appear in the middle of the day



Increasing real-time negative energy price frequency indicates over-generation risk in the middle of the day

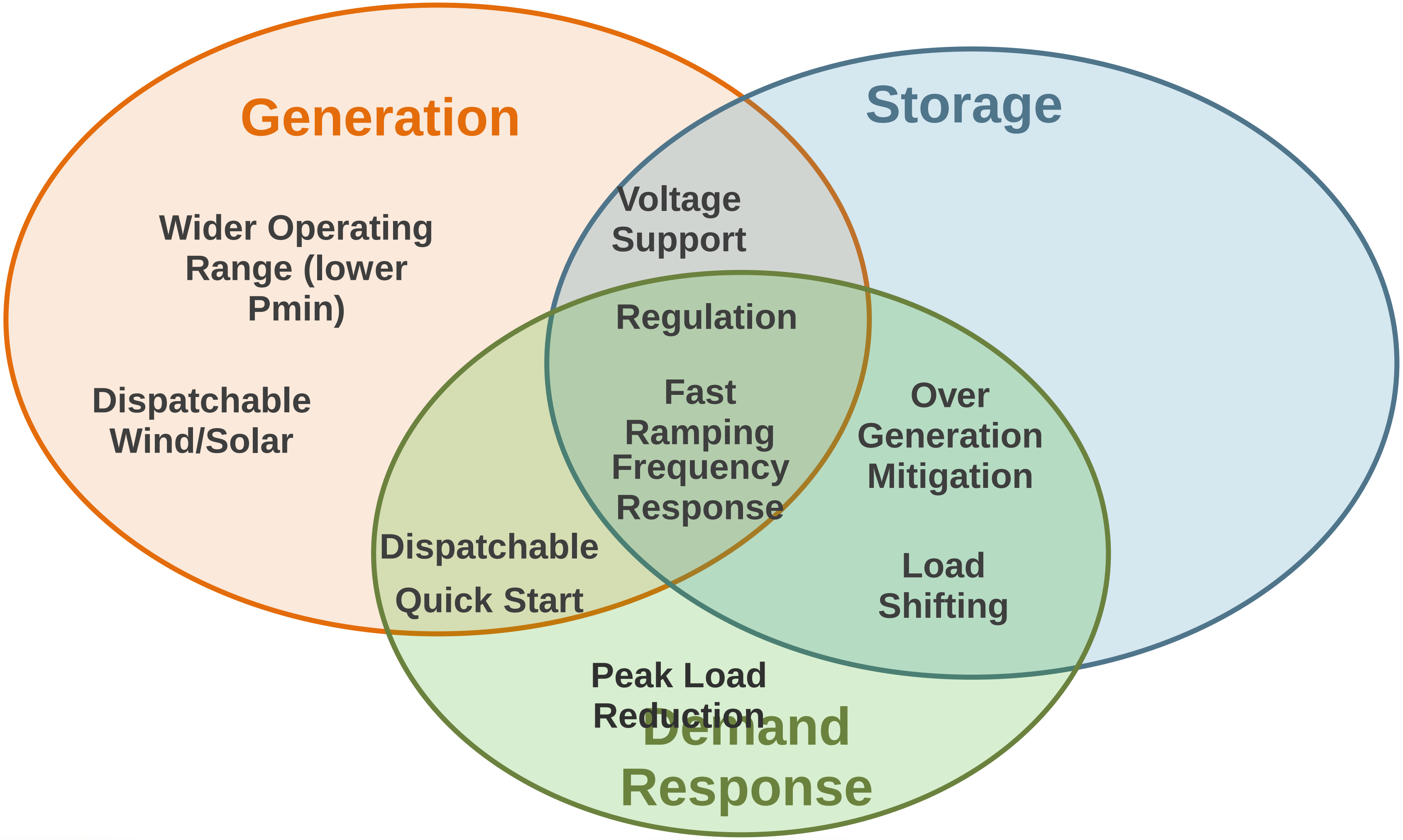
DER can contribute to meeting operational challenges

- Energy Storage can help mitigate over-generation
- Load shifting can help mitigate conventional resource needs
- DERs may also benefit the system by reducing peak demand and thereby avoiding the need for transmission upgrades
- Controlled load dropping can provide spinning reserve and frequency response
- Demand Response can reduce the need for conventional resources
- Distributed Generation can off-set transmission upgrades
- Electric Vehicles can provide regulation service or balancing needs
- Micro grids allows participation in ancillary services markets

Potential challenges DER need to overcome

- Controllability/Sustainability & Visibility of DER
- Security against cyber-attacks
- Response to faults, low voltage ride through, frequency ride through (coordination with IEEE 1547)
- Uniform standards for DER wishing to participate in AS markets
- Time delay between dispatch instructions and actual response
- Coordination of Transmission/Distribution voltage control devices
- Coordination during system restoration following major disturbances
- Impact on system load forecast
- Market design and pricing policy

Meeting operational challenges with both transmission and distribution resources



Generation

Storage

Demand Response

Wider Operating Range (lower Pmin)

Dispatchable Wind/Solar

Voltage Support

Regulation

Fast Ramping

Frequency Response

Over Generation Mitigation

Dispatchable

Quick Start

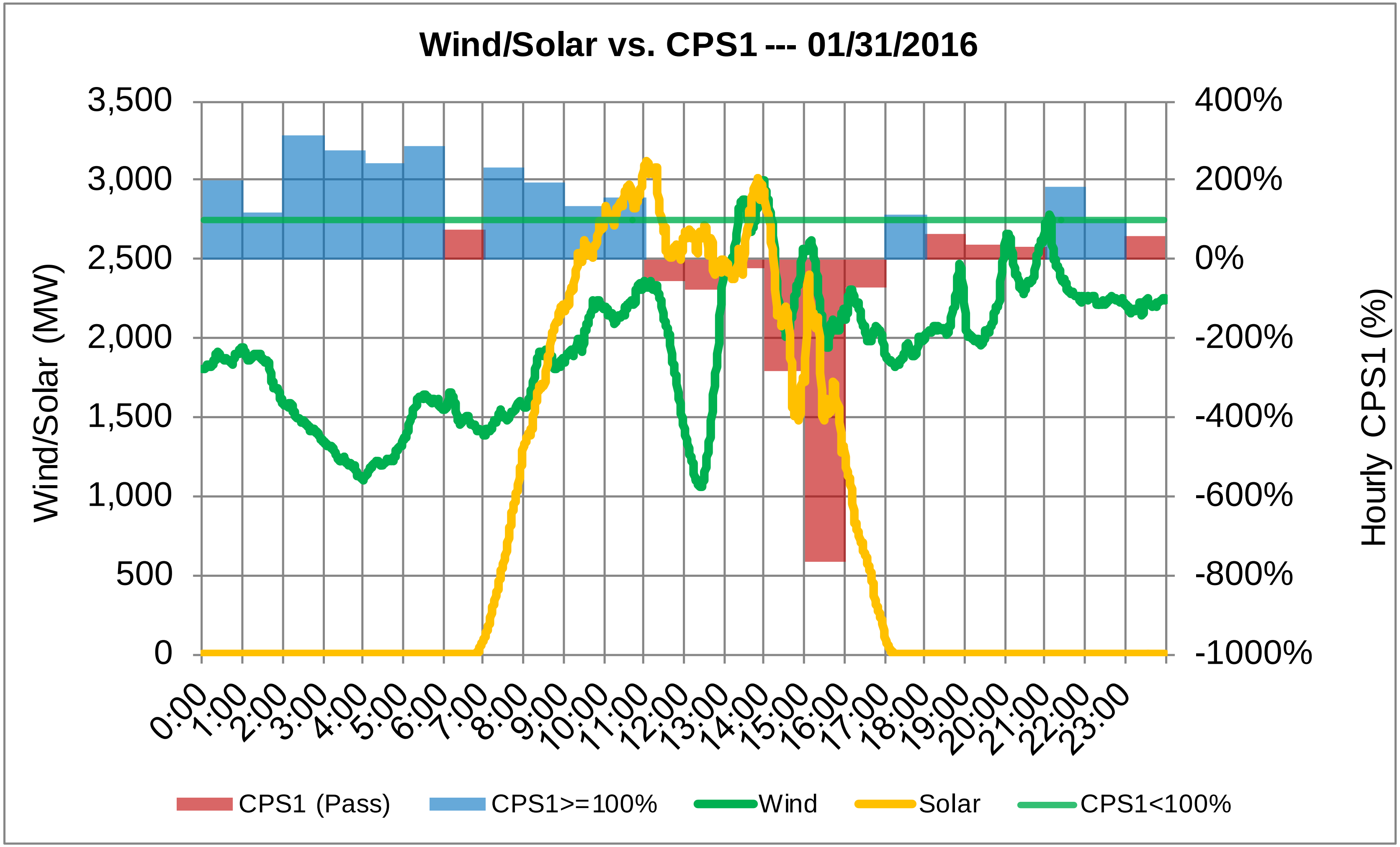
Load Shifting

Peak Load Reduction

Appendix

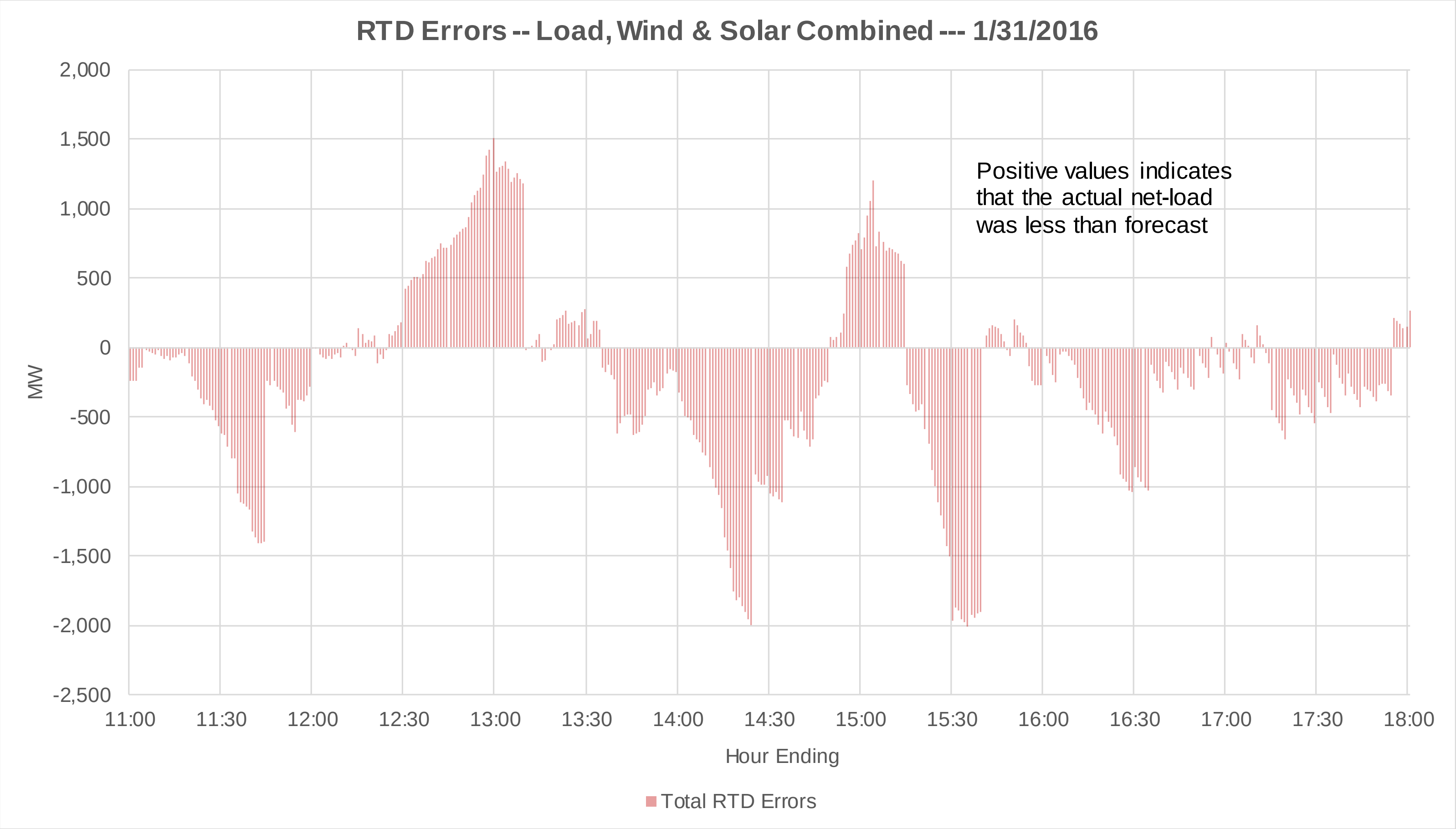
- On a windy/cloudy days, the variability of VERs can lead to regulation depletion and ultimately Control Performance Standard exceedances

ISO's CPS1 score for the day was 63.9% and for 11 hours its hourly scores were below 100% on January 31



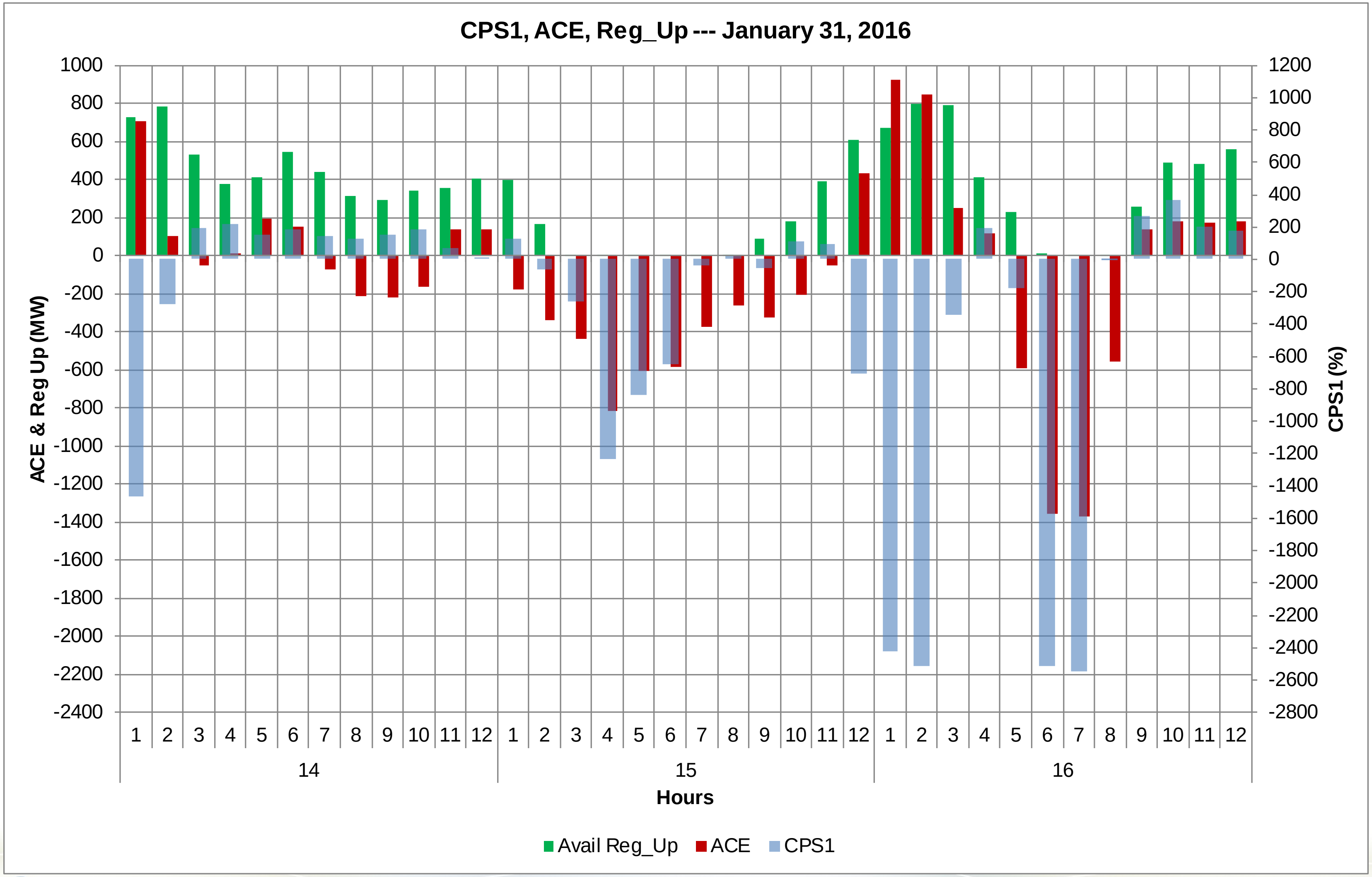
CPS1 is evaluated on a rolling 12-month average. Over the past few years, the rolling average has been declining as a result of some poor daily performances. Thus, the CAISO need to take measures to improve daily performance on days with higher variability.

On this windy/gusty day, the RTD **net-load** forecast errors was 1,503 MW greater than actual in HE 13 and was as lower than actual net-load by 2007 MW in HE16



Positive values indicates that the actual net-load was less than forecast

Regulation up was depleted in HE15 for approximately 35 minutes and for approximately 15 minutes in HE16 --- 1/31/2016



Regulation down was depleted for approximately 15 minutes during the beginning of HE14 and approximately 25 consecutive minutes in HE15 & HE16 --- 1/31/2016